PUBLIC UTILITIES COMMISSION

HAWAIIAN ELECTRIC COMPANY, INC.
RATE CASE (TY 2009)
Docket No. 2008-0083

HECO's
OPENING BRIEF

January 5, 2010

Goodsill Anderson Quinn & Stifel

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of **HAWAIIAN ELECTRIC COMPANY, INC.** **For Approval of Rate Increases and Revised Rate Schedules and Rules**	**DOCKET NO. 2008-0083**

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HAWAIIAN ELECTRIC COMPANY, INC.'S OPENING BRIEF

EXHIBITS A & B

AND

CERTIFICATE OF SERVICE

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

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HAWAIIAN ELECTRIC COMPANY, INC.'S OPENING BRIEF

This Opening Brief is respectfully submitted on behalf of **Hawaiian Electric Company, Inc.** ("Hawaiian Electric", or the "Company" or "HECO").

Following an extensive discovery process in this proceeding, **Hawaiian Electric, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs** (the "Consumer Advocate" or "CA"), and **the Department of the Navy on behalf of the Department of Defense** (the "DOD")[1] entered into a comprehensive **Stipulated Settlement Letter** ("Settlement Agreement"), which was filed on May 15, 2009. In their Settlement Agreement, the Parties reached agreement on all but two issues – (1) the fair and reasonable rate of return on common equity to be used in determining Hawaiian Electric's Revenue Requirement for its 2009 test year Results of Operations, and (2) the appropriate level of Informational Advertising cost to be included in the test year Operations and Maintenance ("O&M) expenses.

In its Interim Decision and Order ("Interim D&O" or "IDO") issued July 3, 2009, in its information requests, and at the Panel Hearings moderated by Scott Hempling of the **National**

[1] Hawaiian Electric, the Consumer Advocate and the DOD are jointly referred to as the "Parties".

Regulatory Research Institute ("NRRI"), the **Hawaii Public Utilities Commission** (the "Commission") posed a significant number of questions regarding the components of the test year Revenue Requirement, as well as other regulatory matters.

Therefore, this Opening Brief addresses not only the two contested issues, but also addresses in detail the evidentiary record supporting the settled components of Revenue Requirement, and Hawaiian Electric's responses to the other questions and issues raised by the Commission.

Hawaiian Electric will provide its form of Proposed Findings and Conclusions with its Reply Brief. With respect to the settled components of Revenue Requirement, it will outline in much briefer fashion the key facts and points presented in much greater detail in this Opening Brief. With respect to the contested issues, it will take into account the points raised by the Consumer Advocate and the DOD in their Opening Briefs, and Hawaiian Electric's responses to those points.

I. RESULTS OF OPERATIONS

A. ADJUSTMENTS TO RESULTS OF OPERATIONS

There was some discussion at the hearing with respect to cost containment measures initiated in the second half of 2009, whereby certain costs have been reduced in order to mitigate to some extent the impact on earnings of differences in the test year estimates and the actual results for 2009.. As of June 30, 2009 the 12 months trailing ROE was only 6.4% (on a ratemaking basis),[2] 410 basis points less than the interim ROE of 10.5%. As of September 30, 2009, the 12 months trailing ROE was only 6.52% (on a ratemaking basis).[3]

[2] Rate of Return on Rate Base and on Common Equity for 12 months ended June 30, 2009 (ratemaking method), filed August 7, 2009.

[3] Rate of Return on Rate Base and on Common Equity for 12 months ended September 30, 2009 (ratemaking method), filed November 2, 2009.

Hawaiian Electric has taken some short-term measures to protect its financial integrity and credit standing – to make up in part for lower than expected sales and built in delays in getting rate relief – but those measures are not sustainable, and cannot be continued without impacts to service quality and reliability, as well as delaying its ability to achieve energy objectives.

As a result, the revenue requirement with respect to settled issues generally should not be adjusted, even if some of the inputs to the settlement have changed. As the Consumer Advocate and DOD have both stated, the settlement involves a fair amount of give and take already. Moreover, the expense side of the settlement revenue requirement cannot be reduced without looking at the total picture – and what is driving the need to contain costs.

First, sales are lower than the test year estimate by 87.5 GWh through September 2009, at a cost of another $8 million in net revenue requirements (after fuel and purchased energy). (Recorded September 2009 year-to-date energy sales were 1.6% less than the year-to-date energy sales forecasted for the 2009 test year.[4]) Again, Hawaiian Electric knew about the sales shortfall when it entered into the settlement, and was prepared to absorb the impact through June, but the stipulated protection in the form of sales decoupling after the date of the interim, which was agreed to by the Parties in the Settlement Agreement, was not approved by the Commission.

Second, the interim rate increase was delayed. The settled rate increase is that needed at the beginning of the test year. Hawaiian Electric knew it would be delayed by five months when it filed its rate case, and by six months when it entered into the settlement, and was prepared to live with that delay – even though the cost was $40 million in revenue requirements based on the settlement, or $30 million based on the interim received. The interim was delayed another

[4] HECO Hearing Exhibit 3, Docket No. 2008-0083, HECO T-2, page 2, re-filed (on a confidential basis) November 3, 2009.

month, however, which cost another $5 million, based on the interim received.

Third, the cost of CIP CT-1 is $193 million, not the $163 million estimated for purposes of the rate case. The difference in revenue requirements is about $2 million. When Hawaiian Electric entered into the settlement, the joint decoupling proposal in the decoupling docket, if implemented, would have allowed recovery of the remainder as of January 1, 2010 through the decoupling RAM. The proposed RAM has been modified, and the adjustment under the revised RAM would be based on the $163 million estimate in this rate case (if approved by the Commission). Hawaiian Electric has filed a motion in the decoupling docket requesting interim approval of sales decoupling and the RAM effective January 1, 2010, but the motion has not been approved as of the date of this brief.

Fourth, the settlement assumed $13 million in annual rate relief for CIP CT-1 at the beginning of July – and the Company has lost at least 6 months of the requested relief at a cost of another $6.5 million.

As stated in the Company's closing argument, however, that does not mean that Hawaiian Electric is unwilling to update at all. Hawaiian Electric is willing to reduce the settlement revenue requirements for certain items. At the same time, some of the items that were taken away by the Interim D&O would have to be allowed.

The list of the reductions includes the following, which are discussed in more detail in other sections of the brief:

(1) Deferral of the Ellipse 6 upgrade project in O&M expense – $1.187 million, approximately $1.303 million in revenue requirements.

(2) For the remaining 2% wage increase for merit employees that did not take place on May 1, 2009, including payroll taxes - $680,000 ($628,000 +$52,000), approximately $746,000 in revenue requirements.

(3) Adjustment for the expense of two leases for office space not incurred in the

test year - $224,000, approximately $ 246,000 in revenue requirements.

(4) State investment tax credit correction - $223,500 reduction in average rate base, $26,000 in revenue requirements.

(5) The reduction in the rate of return on rate base resulting from the ROE update. Dr. Morin reduced his ROE recommendation to 10.75%, assuming the cost recovery mechanisms are approved. This was an unsettled issue. This reduces Hawaiian Electric's rebuttal position by about $3 million annually.

The list of reductions made as a result of the Interim D&O that should be added back includes:

(1) CIP CT-1 Costs, as reflected in the Motion for a Second Interim Increase:

O&M expense	
Production O&M expense	$1,369,000
Admin & Gen O&M expense	$138,000
Payroll tax expense	$48,000
Total O&M Expense	$1,555,000

Rate Base Average Balance	
Net Cost of Plant in Service	$83,770,000
Accumlated Deferred Income Taxes	($2,259,000)
Total Rate Base Average Balance	$81,511,000

$12.671 million in revenue requirements.

(2) "HCEI-related" positions - $1,051,000 ($697,000 in O&M labor expenses, $303,000 in employee benefits and $51,000 in payroll taxes), approximately $1.2 million in revenue requirements.

(3) Wage increases (rollback to 2007 wage levels) - $3.032 million, approximately $3.4 million in revenue requirements.

If the employee discount is eliminated, Hawaiian Electric is not asking that the cost of any replacement benefit be added back at this time. The net effect would be additional revenues of $1.1 million at proposed rates, plus a reduction in OPEB expense, net of the transfer to capital portion of $383,000 per year, based on the employee discount component of the test year OPEBs estimate. The average rate base would be reduced by $275,000. The additional reduction on revenue requirements would be approximately $464,000.

Prior to filing its Reply Brief, Hawaiian Electric intends to see if the Consumer Advocate and DOD are willing to agree to a reduction in the stipulated revenue requirements. In its reply brief, Hawaiian Electric will incorporate any agreed upon reductions into its 2009 test year revenue requirement and provide results of operations reflecting these revisions.

II. SALES AND REVENUES

A. SALES

Hawaiian Electric's estimate of total electricity sales for the 2009 test year is 7,484.7 GWh. HECO T-2 Rate Case Update at 6. The Consumer Advocate and DOD are in agreement with Hawaiian Electric's test year estimate of total electricity sales. Settlement Exhibit at 3-4. In Direct Testimony, the Company projected test year sales of 7,657.8 GWh. HECO T-2 at 1. However, it its HECO T-2 Rate Case Update, the Company lowered its projection to 7,484.7 to reflect lowered sales expectations and an increasingly pessimistic economic outlook. See HECO T-2 Rate Case Update at 1, 6, 7; Settlement Exhibit at 3. In light of the updated sales estimate, the Consumer Advocate took the position that the best available forecast of test year sales should be used to establish the rate case revenue requirement, so that decoupling adjustments, if decoupling is approved in this proceeding, are zero-based to the extent possible. See CA-T-1 at 43. In settlement, the parties agreed for settlement purposes to reflect the lower estimated test year 2009 electric sales of 7,474.7. Settlement Exhibit at 4.

Hawaiian Electric's estimate of the average number of customers for the 2009 test year is 296,210. HECO-212; HECO T-2 at 1, 28; HECO T-2 Rate Case Update at 6, 13. The Consumer Advocate and DOD are in agreement with Hawaiian Electric's test year estimate of the average number of total customers. Settlement Exhibit at 4.

B. REVENUES

1. Electric Sales Revenues

Hawaiian Electric's 2009 test year total electric sales revenues, based on the test year sales estimate and average number of customers, are $1,291,619,000 at current effective rates and $1,371,318,000 at proposed rates, for an increase of $79,699,000. Settlement Exhibit at 8; HECO-S-310; see HECO ST-3 at 1-2.

Hawaiian Electric proposed rate step increase treatment for CIP CT-1 costs in its Direct Testimony. In Hawaiian Electric's rate case update, the Company proposed a number of different revenue requirement scenarios that are summarized in HECO T-23 Rate Case Update, Attachment 1. In settlement, the parties agreed to test year 2009 electric sales revenues of $1,291,619,000 at current effective rates, and $1,371,318,000 at proposed rates. See Settlement Exhibit at 4-8.

For purposes of interim rates, the Commission directed the Company to remove Schedule E (i.e., the employee electricity rate discount) and adjust other rates based on this change. See Interim D&O at 11. As a result, in the Revised Schedules, electric sales revenues at current effective rates for the interim rate increase were increased by $1,066,900 from $1,291,618,500 (see Revised Schedules HECO T-3, Attachment 3) to $1,292,685,400 (see Revised Schedules HECO T-3, Attachment 4), to reflect a $1,066,900 increase in Schedule R revenues due to removal of the employee electricity rate discount. Revised Schedules Exhibit 3 at 10. (As further discussed elsewhere in this Opening Brief, the removal of Schedule E also resulted in an adjustment of the Company's OPEB calculations.)

In Supplemental Testimony, Hawaiian Electric reflected electric sales revenues of $1,291,619,000 at current effective rates and $1,371,318,000 at proposed rates, for an increase of $79,699,000, consistent with the estimates reached in settlement. See HECO-S-301.

2. Other Operating Revenues

Hawaiian Electric's estimate of test year 2009 Other Operating Revenues (including Gain on Sale of Land) at current effective rates is $4,755,000 and 4,876,000 at proposed rates. See HECO-S-301.

In Direct Testimony, Hawaiian Electric estimated its 2009 test year Other Operating Revenues (including Gain on Sale of Land) as follows:

Other Operating Revenues, including Gain on Sale of Land HECO 2009 Test Year Estimate – Direct Testimony ($ thousands)		
Base Case	Interim (w/o CT-1)	CT-1 Full Cost
Current Effective Rates	Current Effective Rates	Current Effective Rates

$5,102	$5,102	$5,102
Present Rates	Present Rates	Present Rates
$5,034	$5,034	$5,034
Proposed Rates	Proposed Rates	Proposed Rates
$5,211	$5,200	$5,222

HECO-301; see HECO T-3 at 6. (In Direct Testimony, Hawaiian Electric's 2009 test year estimate of Gain on Sale of Land was $615,000. The Consumer Advocate and DOD did not propose any adjustment to this estimate and therefore it remained unchanged.)

Hawaiian Electric did not revise its 2009 test year estimates for Other Operating Revenues in its rate case update.

The Consumer Advocate, in its direct testimony, proposed an upward adjustment to Other Operating Revenues of $121,000, based on (1) a decrease in late payment charge estimates by $45,000 as a result of lower sales, and (2) an increase in revenues of $166,000 for non-sales electric utility charges, for a net adjustment of $121,000. See CA-T-1 at 48-50; CA-101, Schedules C-1 and C-2.

In settlement, the parties agreed to estimates of Hawaiian Electric's 2009 test year Other Operating Revenues of $4,755,000 at current effective rates and $4,877,000 at proposed rates (including Gain on Sale of Land). See Settlement Exhibit at 10-11.

The Revised Schedules reflect 2009 test year estimates of Other Operating Revenue of $4,755,000 at current effective rates and $4,861,000 at proposed rates (including Gain on Sale of Land). See Revised Schedules Exhibit 1 at 1.

3. FERC Form 1 Other Operating Revenues Increases

In its information requests, the Commission made several inquiries regarding the increase in other operating revenues included in Hawaiian Electric's FERC Form 1, from $4,027,498 in 2006 and $4,410,392 in 2007 to $6,528,974 in 2008. See PUC-IR-175 thru -180. As explained in response to PUC-IR-180, the Company's field collection charge in FERC Form 1 increased in 2008 because the rate increased from $15.00 to $20.00 with the approval of final rates in the HECO 2005 test year rate case (Docket No. 04-0113), effective June 20, 2008. The return check fee increased in 2008 because the rate increased from $7.50 to $16.00 with the approval of final rates in the HECO 2005 test year rate case, effective June 20, 2008. The delinquent payment fees increased in 2008 because of higher electric bills related to high fuel costs in 2008. Fuel costs are expected to be lower in 2009, which is reflected in the 2009 test year estimate of delinquent payments. Service establishment fees increased in 2008 because the rate increased from $15.00 to $20.00 and the additional charge for same day service or for service outside of normal business hours increased from $10.00 to $25.00 with the approval of final rates in the HECO 2005 test year rate case, effective June 20, 2008. Response to PUC-IR-180 at 1.

In addition, Other electric revenues – gross increased in FERC Form 1 from 2006 through 2008 largely because of the project management service contract that Hawaiian Electric has with the State of Hawaii DOT Airports Division to provide contract management services to assist with the development of the emergency power facility. These services are deferred when incurred and recognized as expenses when the DOT is billed. As the Company bills the Airports Division for the work, the revenues are recorded in Account No. 456000. HECO's expenses for the work provided to the Airports Division are recorded in Account No. 546. In 2006, Hawaiian Electric did not record any revenue under the contract with the Airports Division. In 2007, HECO billed $59,000 to the Airports Division under the contract. In 2008, Hawaiian Electric billed $652,000 to the Airports Division under the contract. There is no revenue or expense related to this work included in the rate case estimates. Response to PUC-IR-180 at 2.

The increase in Account 45600 from 2006 to 2007 was also due to revenues for interconnection requirements studies. In 2006, revenues from interconnection requirements studies amounted to $3,700. In 2007, revenues from interconnection requirements studies amounted to $235,000. In 2008, revenues from interconnection requirements studies amounted to $273,000. Costs for interconnection requirements studies are reflected in Account No. 557. While the amounts recorded in Account No. 45600 have increased from 2006 through 2008, the expenses included in other accounts have also increased. Hawaiian Electric is required to pay PSC taxes and PUC fees on such billings; thus, the Company's records such billings as Other Operating Revenues. Response to PUC-IR-180 at 2.

III. OPERATIONS AND MAINTENANCE EXPENSES

A. FUEL AND PURCHASED POWER EXPENSE

1. Fuel Expense

The Company's test year estimate for fuel expense was $816,654,000 in direct testimony consisting of $809,058,000 of fuel oil expense and $7,596,000 of fuel-related expense. HECO T-4 at 4 and HECO-401. The test year fuel expense represents the cost of fuel required by Hawaiian Electric to produce the energy required, less purchased energy, to meet the projected needs of its customers. The two primary factors in the determination of the test year fuel oil expense are fuel price and projected fuel consumption (i.e., the quantity of fuel needed to produce the required energy). The derivation of fuel oil expense presented in direct testimony is discussed in HECO T-4 on pages 4 through 21. See also HECO-405. The test year sales were based on the Company's March 2008 Sales Update as provided in HECO T-2 at 2. The test year fuel prices for low sulfur fuel oil ("LSFO") and diesel were based on actual April 2008 contract prices, and the price for biodiesel was based on an estimate of the April 2008 price as if deliveries had commenced under the Imperium Biodiesel Supply contract. HECO T-5 at 6.

For settlement discussions, HECO reran its production simulation in April 2009 and agreed to use (1) the lower sales for the 2009 test year as reflected in HECO's September 2008 Sales and Peak Forecast, (2) an in-service date of July 1, 2009 for Hoku Solar, and (3) December 2008 fuel prices. The results of HECO's April 24, 2009 ("April 2009 Update") production simulation run, including updated exhibits and workpapers supporting HECO's revised fuel oil expenses, fuel related expenses, fuel prices, fuel inventory and purchased power expenses were provided to the Consumer Advocate and the DOD on April 30, 2009. Settlement Exhibit at 13-14. See also Settlement, HECO T-4, Attachment 3 (April 2009) Update and Settlement, HECO T-5, Attachment 3 (April 2009 Update).

Using HECO's April 2009 Update assumptions for (1) Kalaeloa's fuel price, (2) avoided cost energy rates, (3) HPower energy rate and (4) AES availability (kWh) for the months of October through December 2008, the Consumer Advocate independently reran another production simulation in May 2009. Based on its review, the Consumer Advocate found its May 2009 Update and HECO's April 2009 Update production simulation results to be comparable and reasonable. For purposes of settlement, the Parties agreed to use HECO's April 2009 Update production simulation results and accepted HECO's April 2009 Update 2009 test year total fuel expense, purchased power expense, sales heat rates, fuel inventory and ECA Factor at current effective rates. Settlement Exhibit at 14.

As agreed by the Parties in the Settlement, the Company's 2009 test year estimated total fuel expense is $438,348,000 consisting of $431,206,000 of fuel oil expense and $7,142,000 of fuel-related expense. Settlement Exhibit at 14. See also Settlement, HECO T-4 Attachment 1 at 1 (April 2009 Update) and Settlement, HECO T-5 Attachment 1, at 1 and 4 (April 2009 Update).

2. **Purchased Power Expense**

The purchased power expense presented in direct testimony was $477,055,480 which consisted of $369,123,533 for purchased energy expenses and $107,931,947 for firm capacity expenses. HECO T-6 at 1 and HECO-601.

As noted in Section 1.a above, the Parties agreed to use the results of Hawaiian Electric's April 2009 Update production simulation and accepted HECO's April 2009 Update purchased energy estimate of 3,363 GWh, as well as Hawaiian Electric's purchased power expense of $346,467,000 consisting of $238,646,000 for energy payments and $107,821,000 for firm capacity payments. Settlement Exhibit at 15. See also Settlement, HECO T-6, Attachments 1 and 2 (April 2009 Update).

3. **Generation Heat Rate**

The total test year net heat rate for Hawaiian Electric presented in direct testimony was 10,635 Btu/kWh; the central station unit heat rate was also 10,635 Btu/kWh; the steam heat rate was 10,547 Btu/kWh; the combustion turbine (with diesel) heat rate was 23,457 Btu/kWh; the combustion turbine (with biodiesel) heat rate was 19,236 Btu/kWh; and the substation distributed generation heat rate was 10,409 Btu/kWh . HECO-403.

As noted in Section 1.a above, the Parties agreed to use the results of Hawaiian Electric's April 2009 Update production simulation and accepted HECO's April 2009 Update for net and sales heat rates. The total test year net heat rate presented in Hawaiian Electric's April 2009 update, and agreed to by the Parties in the Settlement, was 10,635 Btu/kWh; the central station unit heat rate was also 10,635 Btu/kWh; the steam heat rate was 10,568 Btu/kWh; the combustion turbine (with diesel) heat rate was 23,466 Btu/kWh; the combustion turbine (with biodiesel) heat rate was 19,287; and the substation distributed generation heat rate was 10,409

Btu/kWh . Settlement, HECO T-4 Attachment 1 at 4 (April 2009 Update).

The net heat rate directly affects the "sales heat rate." The sales heat rate is calculated in a similar manner as the net heat rate, except the sales heat rate is the heat content of the fuel consumed per kWh of sales. The sales heat rate in the form of a Generation Efficiency Factor is used in the Energy Cost Adjustment Clause to translate the base generation cost in cents per MBtu to the weighted base generation cost in cents per kWh of sales. HECO T-4 at 23. For Hawaiian Electric, the sales heat rate is computed by dividing the test year fuel consumption (in MBtus) by the proportion of sales provided by Hawaiian Electric's generation (in kilowatt-hours). The resulting base case Generation Efficiency Factor presented in direct testimony was 0.011185 MBtu/kWh sales. HECO T-4 at 23; HECO-403. The Generation Efficiency Factor presented in Hawaiian Electric's April 2009 update, and agreed to by the Parties in the Settlement, is 0.011184 MBtu/kWh sales. Settlement, HECO T-4 Attachment 1 at 4 (April 2009 Update).

4. <u>Energy Cost Adjustment Factor</u>

As presented in direct testimony, the test year Energy Cost Adjustment Factor ("ECAF") is 7.221 ¢/kWh at current rates, and 0.000 ¢/kWh at proposed rates as shown in HECO-1033. HECO T-10 at 62.

HECO recalculated the ECAF based on the lower sales forecast and December 2008 fuel prices (including Kalaeloa). The resulting ECAF was 0.152 cents per kWh at current effective and present rates which, when applied to 7,484.7 gWh, yielded ECAC revenues of $11,376,800 at current effective and present rates as shown in Settlement, HECO T-3, Attachment 1, page 1, column B. The ECAF at proposed rates was 0.000 cents per kWh. Settlement Exhibit 1 at 16. See also Settlement, HECO T-10, Attachment 1 at 1.

In the Settlement, the Parties agree that the ECAF at current effective and present rates is 0.152 cents per kWh, 0.000 cents per kWh at proposed rates, and the sales heat rates used in the ECAF as fixed efficiency factors at proposed rates are:

LSFO:	0.011114 mbtu/kwh
Diesel:	0.024582 mbtu/kwh
Biodiesel:	0.016762 mbtu/kwh
Other plants:	0.011184 mbtu/kwh
Weighted average:	0.011184 mbtu/kwh

Settlement Exhibit at 16. See also Settlement, HECO T-10, Attachment 1 at 9.

The ECAF, ECAC and compliance with Act 162 are discussed elsewhere in this Opening Brief.

B. PRODUCTION AND T&D EXPENSES

1. Production O&M Expenses

Hawaiian Electric's 2009 test year estimate for Production O&M expenses (other than fuel oil and purchased power expense) presented in direct testimony was $80,391,000. HECO T-7 at 3; HECO-701. As discussed below, it is Hawaiian Electric's position that the Commission's Final Decision and Order should allow the amount of $77,691,000 for the Production O&M expense for the 2009 test year.

During the course of this proceeding, the Production O&M expense estimate for the 2009 test year was revised several times. The table below summarizes the revisions:

	Direct Testimony	Rate Case Update	Settlement	Response to Interim D&O	2nd Interim CT-1 w/ water treatment
Production Operations					

Labor	15,402,000	15,829,000	15,632,000	14,521,000	14,924,000
Non-Labor	16,998,000	19,700,000	16,930,000	16,535,000	16,930,000
Subtotal	32,400,000	35,529,000	32,562,000	31,055,000	31,853,000
Production Maintenance					
Labor	17,610,000	17,610,000	17,491,000	16,859,000	17,095,000
Non-Labor	30,381,000	30,428,000	28,920,000	28,408,000	28,744,000
Subtotal	47,991,000	48,038,000	46,411,000	45,267,000	45,838,000
Production O&M Total					
Labor	33,012,000	33,439,000	33,123,000	31,379,000	32,018,000
Non-Labor	47,379,000	50,128,000	45,850,000	44,943,000	45,673,000
Total	80,391,000	83,567,000	78,973,000	76,322,000	77,691,000

The components of the revisions shown in the table above are discussed below.

Rate Case Update

Hawaiian Electric's Rate Case Update for Production O&M expense, filed December 12, 2008, revised the Production O&M expense test year estimate to $83,567,000, an increase of $3,176,000 over the Production O&M expense test year estimate of $80,391,000 in direct testimony. HECO T-7 Rate Case Update, Attachment 1 at 1; HECO T-7 Rate Case Update at 1-2. The increase is the net result of revisions to the following specific Production O&M expense estimates:

- HCEI Implementation Study: <u>$2,220,000 increase</u> (Production Operations Non-labor). (Environmental Department - $20,000; Power Supply Engineering Department - $400,000; System Planning Department - $900,000; System Operation Department - $200,000; Power Supply O&M Department - $700,000.) Of the total increase of $3,176,000 in the HECO T-7 Rate Case Update for Production O&M expenses, $2,220,000 relates to the estimated costs in 2009 for outside services (non-labor) for the HCEI Implementation Study described below. Hawaiian Electric's strong preference is to recover the costs for the HCEI Implementation Study through the Renewable Energy Infrastructure Program ("REIP") Surcharge proposed in Docket No. 2007-0416. This is the approach agreed upon by the parties to the HCEI Agreement discussed below. The Commission issued on December 11, 2009, its Decision and Order in Docket No. 2009-0162, *For Approval of Recovery of Big Wind Implementation Studies Costs Through the Renewable Energy Infrastructure Program Surcharge*, that allows Hawaiian Electric to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness. The Commission, however, did not authorize a specific amount to be recovered until a detailed review is conducted at a later date on the actual incurred charges. Since the other alternative is to include the costs in the 2009 test year, Hawaiian Electric has included the costs in this update pending approval of the REIP Framework, and the filing of an application pursuant to the Framework for the HCEI Implementation Study. HECO T-7 Rate Case Update at 2-3.

- Green House Gases: <u>$45,000 increase</u> (Production Operations Non-labor). Hawaii's Global Warming Solutions Act (2007) requires tracking and reduction of green house gases to 1990 levels by the year 2020. There are various mechanisms to track green house gases, including joining the Climate Registry or other similar organizations. The $45,000 expense is estimated to cover the cost of membership in such a tracking organization and for consulting services required to independently verify Hawaiian Electric's green house gas inventory. HECO T-7 Rate Case Update at 21.
- Renewable Energy Power Purchase Division: <u>$305,000 increase</u> (Production Operations Labor: $161,000; Production Operations Non-Labor: $144,000). The labor expense is for the net increase of two positions associated with the reorganization of the Power Purchase Division into two separate divisions: a new division, the Renewable Energy Power Purchase Division, to manage the increasing number of renewable energy power purchase negotiations; and the Power Purchase Contract Administration Division that will assume the role of the former Power Purchase Division. HECO T-7 Rate Case Update at 22-24. Regarding the non-labor expense, as a result of Hawaiian

Electric's commitments to increased levels of renewable energy from independent power producers, there are also corresponding increases in the non-labor expenses for outside services, materials and supplies and travel. HECO T-7 Rate Case Update at 22, 24-25. See also HECO T-7 Rate Case Update, Attachment 6.

- Renewable Energy Planning Division: $254,000 increase. (Production Operations Labor: $149,000; Production Operations Non-Labor: $105,000). The System Planning Department created a new division, Renewable Energy Planning, to manage the increasing work load in the department associated with the integration of new renewable energy resources. This resulted in a net increase of four positions in the System Planning Department. Hawaiian Electric's O&M expense allocation results in a net increase in labor expense of $149,000. The net change in non-labor expense of $105,000 is a projection of increased outside services costs (other than for the Implementation Studies) associated with the study and evaluation of integrating new renewable energy projects on the utility grid while ensuring the safe and reliable operation of the system. HECO T-7 Rate Case Update at 26-32. See also HECO T-7 Rate Case Update, Attachment 6.
- ITS Cost: $41,000 decrease (Production Operations Non-labor). As described in Hawaiian Electric's response to CA-IR-201, the expenses for Iwilei fuel monitoring and CIP Biofuel Truck Rack/Terminal totaling $41,000, were inadvertently included in the 2009 test year estimate for Production O&M Expense for the PSO&M-Admin responsibility area. Therefore, $41,000 was removed from Other Production O&M Expense. HECO T-7 Rate Case Update at 35-36.
- Phone: $10,000 decrease (Production Operations Non-labor). Certain telephone expenses were inadvertently included as RA: PIB Non-Labor expense. These expenses also were included, correctly, in the 2009 test year estimate for RA: PIH, PIK, and PIW Non-Labor expenses.

Accordingly, the expenses were removed from RA: PIB Non-Labor. HECO T-7 Rate Case Update at 36.

- 17" LCD Flat Panel Monitors: <u>$4,000 decrease</u> (Production Operations Non-labor). This expense was inadvertently included as RA: PIB Non-Labor Charges. Expenses for such items are included in the Information Technology and Services (ITS) budget. Accordingly, the expenses were removed from RA: PIB Non-Labor Charges. HECO T-7 Rate Case Update at 36.
- CIP CT-1 Maintenance: <u>$3,000 decrease</u> (Production Maintenance Non-labor). This expense was reduced by $2,700 (rounded to $3,000) from $4,200 to $1,500 due to a revised estimate of the expense which reflects a reduced inspection requirement at the CIP CT-1 facility. HECO T-7 Rate Case Update at 36-37.
- CIP CT-1 Operation: <u>$12,000 decrease</u> (Production Operations Non-labor). This expense for a Campbell Local Emergency Area Network ("CLEAN") membership fee for the CIP CT-1 site was removed. Hawaiian Electric is only required to pay one membership fee to CLEAN and that fee is included in RA: PIK (Kahe Station Ops). HECO T-7 Rate Case Update at 37.
- Photovoltaic Engineer: <u>$33,000 increase</u> (Production Operations Labor). This labor expense is for a Senior Technical Services Engineer (PV Host) position. PV Host was one of the initiatives identified in the Energy Agreement. Starting in July 2009, the additional engineer was anticipated to be required to conduct site assessments, develop bid specifications for PV developers, evaluate proposals, oversee construction, and monitor the PV system performance. Without this new position, the PV Host program would not have sufficient resources to meet its aggressive schedule and the expected customer demand for participation. HECO T-7 Rate Case Update at 37-38.

- Production Simulation: $55,000 increase (Production Operations Non-labor). This expense is for a new production simulation model. Hawaiian Electric has been using a production simulation computer model, called P-Month, to forecast how the generating units on the system will operate on an hour-by-hour basis. Because of a series of problems with that model described in HECO T-7 Rate Case Update at 38-41, Hawaiian Electric obtained a budgetary quote for the MAPS production simulation model developed by GE Energy. The licensing fee is to be allocated among Hawaiian Electric, MECO and HELCO. Hawaiian Electric's share would be $37,500. Hawaiian Electric currently pays about $15,000 to P Plus Corporation, vendor for the P-Month computer model, for the annual maintenance fee, which covers upgrades and technical support, of which 50%, or $7,500, is allocated to Hawaiian Electric. Therefore, the net cost of moving away from P-Month and replacing it with an alternative vendor product would be $30,000 for annual licensing fees in the2009 test year. It was also estimated that Hawaiian Electric would incur about $25,000 in 2009 for training costs to learn how to use the new production simulation model, for a total expense increase of $55,000. HECO T-7 Rate Case Update at 41-42.
- Kahe Fuel Oil Tank #11 Maintenance: $329,000 increase (Production Maintenance Non-labor). This expense item was deferred from 2008 to 2009 to coincide with the Kahe 3 Biofuel testing described in HECO T-7 at 21. Other Production Maintenance expenses from 2009 will be removed, as described below, to result in no net change in 2009 test year Production O&M expenses as a result of this added work. HECO T-7 Rate Case Update at 42.
- Iwilei Fuel Oil Pipeline: $200,000 decrease (Production Maintenance Non-labor). This expense item was removed from 2009 test year Production Maintenance expense, and was performed in 2008, as part of the offset for the increase of $329,000 for Kahe Fuel Oil Tank #11 Cleaning and Inspection expense described above. HECO T-7 Rate Case Update at 42-43.

- Breaker Retrofit: $79,000 decrease (Production Maintenance Non-labor). This expense total was removed from 2009 test year Production Maintenance expense as part of the offset for the increase of $329,000 for Kahe Fuel Oil Tank #11 Cleaning and Inspection expense described above. HECO T-7 Rate Case Update at 43.
- Cathodic Protection: $50,000 decrease (Production Maintenance Non-labor). This expense item was removed from the 2009 test year Production Maintenance expense as part of the offset for the increase of $329,000 for Kahe Fuel Oil Tank #11 Cleaning and Inspection expense described above. HECO T-7 Rate Case Update at 43-44.
- Project Manager, Power Supply Engineering: $84,000 increase (Production Operations Labor). This expense adjustment is for an additional Project Manager position for the Project Management Division in the Power Supply Engineering Department. This additional position is needed based on a forecasted sustained increase in the project management workload associated with the projects, programs and studies required to fulfill the Hawaiian Electric commitments made in the HCEI Agreement. HECO T-7 Rate Case Update at 44.
- HCEI Biofuels Outside Engineering: $50,000 increase (Production Maintenance Non-labor). One of the commitments in the HCEI Agreement is to operate Hawaiian Electric's Substation DG units firing biofuels. An engineering study and technical evaluation of the conversion of the existing Substation DG units from diesel to biodiesel will occur in 2009. HECO T-7 Rate Case Update at 44.
- HCEI Solar Outside Services: $200,000 increase (Production Operations Non-labor). As stated in the HCEI Agreement, Hawaiian Electric, HELCO, and MECO planned to jointly submit an application to the Commission for a utility PV Host Program by March 31, 2009. (On April 30, 2009, the application was filed in Docket No. 2009-0098.) This outside services expense of $200,000 for engineering, consulting and legal services is to support the development of the PV Host

program, prepare the filing to the Commission, and provide assistance to evaluate the applications from customers to participate in the pilot PV Host Program. HECO T-7 Rate Case Update at 45.

Settlement Agreement

The Stipulated Settlement Agreement dated May 15, 2009 ("Settlement") revised the Production O&M expense test year estimate to $78,973,000, a decrease of $4,594,000 from the Production O&M expense test year estimate in the Rate Case Update in the amount of $83,567,000, and a decrease of $1,418,000 from the Production O&M expense estimate in direct testimony in the amount of $80,391,000. Settlement, HECO T-7, Attachment 1, page 3; Settlement Exhibit at 29-33; HECO T-7 at 3. The decrease is the net result of revisions to the following specific Production O&M expense estimates as agreed by the Parties in the Settlement:

- HCEI Implementation Studies – PV Host Program Outside Consulting Charges: $2,420,000 decrease (Production Operations Non-Labor). Hawaiian Electric agreed to remove $2,220,000 of HCEI Implementation Study outside services costs and $200,000 of the HCEI Solar Outside Services expenses for the PV Host Project for recovery through the pending CEIS mechanism. Settlement Exhibit at 30-31.
- Emission Fee Update for Lower Sales: $134,000 increase (Production Operations Non-Labor). The Consumer Advocate and DOD accepted Hawaiian Electric's $134,000 adjustment increasing emission fees due to the passing of Senate Bill No. 1260 during the 2009 legislative session, which removed the "four thousand ton/year cap" in emission fees. Settlement Exhibit at 31.
- Kahe RO Water Supply Savings: $222,000 decrease (Production Operations Non-Labor). The Consumer Advocate proposed a negative adjustment of $222,000 to Production O&M Expense to reflect one-half of the estimated savings from the RO Water utilization. CA-T-1 at 78-79; CA-101,

Schedule C-6 at 1. For purposes of settlement, Hawaiian Electric accepted the Consumer Advocate's $222,000 adjustment reducing Production O&M expense. Settlement Exhibit at 31.

- Normalization of Discretionary Station Maintenance: $1,372,000 decrease (Production Maintenance Non-Labor). The Consumer Advocate proposed an adjustment of $1,372,000 to reduce the Production discretionary maintenance budget to $3,282,000, an amount equal to the annual average of the recorded expenses for similar work from 2006 to 2008. As part of the overall settlement of the issues impacting the test year revenue requirements, the Company accepted the Consumer Advocate's $1,372,000 adjustment. Settlement Exhibit at 31-32.
- Training Cost Outside Services: $217,000 decrease (Production Operations Non-Labor ($109,000); Production Maintenance Non-Labor ($109,000)). The Consumer Advocate proposed a reduction of $217,000 from $403,000 to $186,000 to restate Hawaiian Electric's estimated test year outside services training expenses within the power supply process area forecast to a three year average of historical actual spending as shown in Hawaiian Electric's response to CA-IR-305, Attachment 2. For purposes of settlement, Hawaiian Electric accepted the Consumer Advocate's $217,000 negative adjustment. Settlement Exhibit at 32.
- Payroll and Benefits: $182,000 decrease (Production Operations Labor ($116,000); Production Maintenance Labor ($66,000)). The Consumer Advocate proposed a labor reduction of $508,000 to the Production Labor Expense. CA-101, Schedule C-13. The Consumer Advocate's position was that only certain Production Maintenance Division responsibility areas ("RA") should be excluded from the vacancy calculation to derive their proposed Production Labor Expense Adjustment. The Company proposed that the labor expenses for Production Operating Division RAs be excluded as well, resulting in a reduction of the Production Labor Expense Adjustment by $326,000, from

$508,000 to $182,000. The Consumer Advocate accepted Hawaiian Electric's adjustment. Settlement Exhibit at 32.

- Abandoned Projects Normalization: $8,000 increase (Production Operations Non-labor ($3,000); Production Maintenance Non-labor ($5,000)). The Consumer Advocate proposed an $8,000 adjustment to Production O&M expenses to normalize the historical allowance for abandoned project costs. For purposes of settlement, Hawaiian Electric accepted the Consumer Advocate's adjustment. Settlement Exhibit at 33.
- General Inflation: $9,000 decrease (Production Operations Non-labor ($3,000); Production Maintenance Non-labor ($6,000)). The Consumer Advocate proposed a negative adjustment of $9,000 to Production O&M expense to eliminate the effect of the general inflation factor Hawaiian Electric employed in quantifying the 2009 non-fuel, non-labor expense forecast. The DOD proposed a $32,000 reduction in Production Maintenance expenses for the removal of the general inflation factor. For purposes of settlement, Hawaiian Electric accepted the Consumer Advocate's downward adjustment of $9,000. Settlement Exhibit at 33.
- CIP CT-1 Waste Water Treatment Chemicals: $49,000 decrease (Production Operations Non-labor). As part of the settlement negotiations, Hawaiian Electric removed $49,000 from Production Operations non-labor expense for CIP CT-1 Waste Water Treatment Chemicals as stated in its response to CA-IR-297. Settlement Exhibit at 29.
- CIP CT-1 Boiler Water Treatment: $42,000 decrease (Production Operations Non-labor). As part of the settlement negotiations, Hawaiian Electric removed $42,000 from Production Operations non-labor expense for CIP CT-1 Boiler Water Treatment as stated in Hawaiian Electric's response to CA-IR-297. Settlement Exhibit at 29.

- CIP CT-1 Demin/Evap Chemicals: $14,000 decrease (Production Operations Non-labor). As part of the settlement negotiations, Hawaiian Electric removed $14,000 from Production Operations non-labor expense for CIP CT-1 Demin/Evap Chemicals as stated in Hawaiian Electric's response to CA-IR-468. Settlement Exhibit at 29.
- CIS expenses: $80,000 decrease (Production Operations Labor ($6,000); Production Operations Non-labor ($48,000); Production Maintenance Non-labor ($26,000)). Following the filing of Hawaiian Electric's Rate Case Update, the Company determined that there was little likelihood of completing CIS during the test year and the test year estimate was revised to reflect the delay of the implementation date. The reduction in O&M expenses allocated to the Production block of accounts was $80,000. Settlement Exhibit at 25-26 and 29. See also Settlement, HECO T-9, Attachment 2.
- IRP Planning expenses: $1,000 decrease (Production Operations Non-labor). The Consumer Advocate proposed to reduce test year non-labor expense for IRP/CESP by $62,000 by averaging 2006, 2007, and 2008 recorded amounts (CA-T-1, pages 113 to 114; CA-101, Schedule C-12). The Consumer Advocate proposed the entire negative adjustment of $62,000 be applied to A&G O&M expenses. Hawaiian Electric accepted the Consumer Advocate's proposed adjustment. The portion of the adjustment allocated to Production O&M expense is $1,000. Settlement Exhibit at 29 and 51.
- Merit Labor: $128,000 decrease (Production Operations Labor ($75,000); Production Maintenance Labor ($53,000)). Given the current economic environment, and in the interest of reaching a global settlement in this proceeding, the Company proposed to lower the O&M labor expenses for merit employees for 2009 by $532,000. The Consumer Advocate and the DOD agreed to the reduction. The portion of the reduction allocated to Production O&M expense is $128,000. Settlement Exhibit at 24-25. See also Settlement HECO T-13 Attachment 1.

Revised Schedules in Response to Interim D&O

In accordance with the Interim D&O, the Company filed on July 8, 2008 revised schedules and explanations of certain adjustments to the Company's 2009 test year estimates, as required in Sections II.1. and II.2. of the Interim D&O. This resulted in a revised Production O&M test year expense estimate of $76,322,000, a decrease of $2,651,000 from the Production O&M Expense amount agreed to by the Parties in the Settlement. Revised Schedules, Exhibit 1 at 10. The decrease of $2,651,000 is the result of the adjustments to the following Production O&M test year expense estimates:

- HCEI-related positions: $426,000 decrease (Production Operations Labor). In the ID&O, the Commission directed Hawaiian Electric to exclude the costs associated with certain test year employee positions from interim rates, namely, "positions that were created due to the various proposed HCEI initiatives, including the PV Host Program, FIT, the Lifeline Rate Program, decoupling, demand response programs identified in the Energy Agreement, the "Big Wind" project, AMI, and CESP." Interim D&O at 8-9. To comply with the ID&O, Hawaiian Electric removed $697,000 of operations and maintenance ("O&M") labor costs and related adjustments to employee benefits expense of $303,000 and payroll taxes of $51,000 associated with 13 positions that the Company added to the 2009 test year in its Rate Case Update. Revised Schedules Exhibit 3, at 3. The portion of this reduction allocated to Production O&M expense is $426,000. Revised Schedules Attachment A at 1.
- CT-1 in-service date: $1,369,000 decrease (Production Operations Labor ($403,000); Production Operations Non-labor ($395,000); Production Maintenance Labor ($236,000); Production Maintenance Non-labor ($335,000); total Production O&M Labor: ($639,000); total Production O&M Non-labor: ($730,000)). In Section II.2.(a) of the Interim D&O, the Commission denied the inclusion of any cost or rate base additions associated with the CT-1 unit in interim rates. Interim

D&O at 10. In accordance with the agreement of the Parties in the Settlement, the total production O&M costs identified in the Statement of Probable Entitlement was $78,973,000. Statement of Probable Entitlement Exhibit 1 at 1; Settlement Exhibit at 1. The total downward adjustment to remove the Production O&M CT-1 costs from the total Production O&M expense identified in the Statement of Probable Entitlement is $1,369,000. Revised Schedules Exhibit 3 at 8.

- Merit employee wage increases: <u>$679,000 decrease</u> (Production Operations Labor ($283,000); Production Maintenance Labor ($396,000)). Pursuant to Section II.2.(c) of the Interim D&O, the Commission required that for purposes of interim rates, wage levels be restricted to 2007 levels or the most recent actual labor costs filed with the Commission, taking into account the vacancy rate agreed upon by the Parties on pages 22 and 23 of the Settlement. Interim D&O at 11. To comply with the Interim D&O, an O&M labor expense adjustment of $2,829,000 was made to reflect the limiting of the 2009 test year merit salary amounts at the 2007 wage levels, and an associated adjustment for payroll taxes of $203,000. Revised Schedules Exhibit 3 at 11. The portion of the adjustment allocated to Production O&M expense is $679,000. Revised Schedules Attachment A at 1. Although the Company made this adjustment for purposes of interim rates, it is the Company's position that merit employee wage rates should not be held at this level in the rates approved in the Final Decision and Order in this proceeding. The Company's position is explained in more detail elsewhere in this Opening Brief.
- Commodity prices: <u>$177,000 decrease</u> (Production Maintenance Non-labor). In its Interim D&O, the Commission directed Hawaiian Electric, "for interim rates, to update its Other Production Maintenance costs to reflect current commodity prices." Interim D&O at 12-13. To offer an immediate reflection of any commodity pricing decrease that might have an impact on the fabricated materials costs, the Company reflected a $177,000 decrease in Other Production Maintenance costs.

Revised Schedules Exhibit 3 at 19. Although Hawaiian Electric was willing to make a concession on this expense item for the purpose of interim rates, the reduction is not warranted on an on-going basis because of the reasons discussed in HECO ST-7 at 22-28, including: (a) the historical record which demonstrates that Hawaiian Electric has consistently under-forecast the cost for maintenance materials, including 2009; (b) the short-term prices of commodities have been volatile and there has been a significant increase in price indices in recent months above the "lows" experienced in March 2009; (c) the absence of a correlation between raw material costs and the prices paid by Hawaiian Electric for fabricated materials; and (d) the methods Hawaiian Electric utilizes to manage the total expense of its maintenance activity such that increased material prices tends to result in less work being performed and vice versa. Accordingly, Hawaiian Electric considers the maintenance materials estimate of $8,871,000 incorporated its Rate Case Update to be reasonable and should be approved in the Final Decision and Order. Response to CA-IR-309, Attachment 1 at 1.

Motion for Second Interim Decision and Order

The Interim D&O allowed an increase Hawaiian Electric's revenue requirement of $61,098,000. The Production O&M expense for the test year allowed in the Interim D&O was $76,322,000. Revised Schedules Exhibit 1 at 1.

On November 19, 2009, Hawaiian Electric filed its Motion For Second Interim Increase For CIP CT-1 Revenue Requirements, Or In The Alternative, To Continue Accruing AFUDC For The CIP CT-1 Project ("Motion for Second Interim Increase"), in which Hawaiian Electric requested that the Commission issue a second interim decision and order as soon as possible authorizing an additional interim increase in the amount of $12,671,000.[5] Motion for Second Interim Increase at 1. The

[5] The Motion for Second Interim Increase, Exhibit 1, compares the Results of Operations provided in Hawaiian Electric's July 8, 2009 Revised Schedules (that were submitted in response to the Interim Decision and Order filed July 2, 2009) to the Results of Operations that add back in the CIP CT-1 costs

requested second interim increase represents the revenue requirements for the Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1") Project that were included in the Settlement, but were not included in the first interim revenue requirement increase of $61,098,000 authorized by the Interim D&O, and by the Order Approving HECO's Revised Schedules filed August 3, 2009. Motion for Second Interim Increase at 1-2.

The Motion for Second Interim Increase requested an increase in the revenue requirement of $73,769,000 and requested approval of Production O&M test year expenses in the amount of $77,691,000. Motion for Second Interim Increase, Exhibit 1 at 2. This is an increase of $1,369,000 over the amount of the Production O&M test year expense estimate provided in the Interim D&O. (Production Operations Labor $403,000; Production Operations Non-labor $395,000; Production Maintenance Labor $236,000; Production Maintenance Non-labor $335,000; total Production O&M Labor: $639,000; total Production O&M Non-labor: $730,000.) The justification for this increase in the revenue requirement is fully discussed elsewhere in this Opening Brief.

Hawaiian Electric requests that the Final Decision and Order approve Production O&M expenses for the test year in the amount of $77,691,000.

Production Materials Inventory

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that were removed in response to the July 2, 2009 Interim D&O (with the exception of the Fuel Inventory costs). The additional interim increase amount of $12,671,000 includes the revenue requirements for the CIP CT-1 water treatment system costs (of approximately $6.5 million). As reported in the Company's letter to the Commission in Docket No. 05-0145, dated December 16, 2009, the CIP CT-1 water treatment system was placed in service by December 15, 2009. See also Motion for Second Interim Increase Statement of Facts, and Declaration of Robert Isler. In addition, it should be noted that the accrued costs for the CIP CT-1 components that have been closed to plant in service exceed the estimated CIP CT-1 project costs included in the Settlement and thus, the amount proposed to be included in the 2009 test year estimates.

If the revenue requirements relating to the CIP CT-1 water treatment system costs are excluded for purposes of determining the requested second interim increase and for final rates, the amount of the additional interim increase would be reduced to $12,229,000. See Motion for Second Interim Increased, Exhibit 1 at 1, which compares the Results of Operations provided in Hawaiian Electric's July 8, 2009 Revised Schedules to the Results of Operations that add back in the CIP CT-1 costs that were removed in response to the July 2, 2009 Interim D&O (with the exception of the Fuel Inventory costs and water treatment system costs).

Hawaiian Electric's proposed average 2009 test year Production Materials Inventory was $8,809,000 in direct testimony. HECO T-7 at 113; HECO-703. An adjustment was made to Production Materials Inventory in the Settlement . Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals that results in a 2009 average $8,205,000 adjusted production inventory. Settlement Exhibit at 70; Settlement T-18, Attachment 1 at 1. Therefore, Hawaiian Electric requests that the Final Decision and Order approve $8,205,000 for the average 2009 test year Production Materials Inventory.

2. Transmission and Distribution Expenses

Hawaiian Electric's 2009 test year estimate for Transmission and Distribution ("T&D") O&M expenses presented in direct testimony was $44,459,000, consisting of $13,967,000 for Transmission and $30,492,000 for Distribution. HECO T-8 at 1; HECO-801 and HECO-802. As discussed below, it is Hawaiian Electric's position that merit salaries should be based on 2007 salary levels, and, therefore, the Commission's Final Decision and Order should allow the amount of $43,703,000 for the T&D O&M expenses for the 2009 test year.

Hawaiian Electric's 2009 test year estimate for Transmission and Distribution ("T&D") O&M expenses presented in direct testimony was $44,459,000, consisting of $13,967,000 for Transmission and $30,492,000 for Distribution. HECO T-8 at 1; HECO-801 and HECO-802. As discussed in the merit wage section of the instant brief, it is Hawaiian Electric's position that merit salaries should not be based on 2007 salary levels but rather on the 2009 merit wage rate levels. Therefore, the Commission's Final Decision and Order should find that the amount authorized for T&D O&M expense is higher than that of filed in the Revised Schedules filed on July 8, 2009.[6]

[6] The Company has only determined the impact of the additional 2% wage rate level reduction from the Settlement agreement at the total company level. An allocation by NARUC account or process area

During the course of this proceeding, the T&D O&M expense estimate for the 2009 test year was revised several times. The table below summarizes the revisions:

T&D O&M EXPENSES In Thousands	TY ESTIMATE DIRECT	TY RATE CASE UPDATE	SETTLEMENT TOTAL	INTERIM D&O TOTAL
TRANS OPERATIONS				
LABOR	$2,902	$2,881	$2,907	$2,774
NON-LABOR	$4,049	$4,049	$4,012	$4,012
TOTAL	$6,951	$6,930	$6,919	$6,786
TRANS MAINTENANCE				
LABOR	$2,083	$2,067	$2,042	$1,949
NON-LABOR	$4,933	$4,933	$4,898	$4,898
TOTAL	$7,016	$7,000	$6,940	$6,847
TOTAL TRANSMISSION				
LABOR	$4,985	$4,948	$4,949	$4,723
NON-LABOR	$8,982	$8,982	$8,910	$8,910
TRANSMISSION TOTAL	$13,967	$13,930	$13,859	$13,633
DIST OPERATIONS				
LABOR	$6,712	$6,700	$6,645	$6,416
NON-LABOR	$6,901	$6,981	$6,535	$6,535
TOTAL	$13,613	$13,681	$13,180	$12,951
DIST MAINTENANCE				
LABOR	$5,760	$5,715	$5,660	$5,465
NON-LABOR	$11,119	$11,119	$11,005	$11,005
TOTAL	$16,879	$16,834	$16,665	$16,470
TOTAL				

has not been completed and, as a result, a recommended Final Decision and Order amount for T&D O&M expense is not available.

DISTRIBUTION				
LABOR	$12,472	$12,415	$12,305	$11,881
NON-LABOR	$18,020	$18,100	$17,540	$17,540
DISTRIBUTION TOTAL	$30,492	$30,515	$29,845	$29,421
GRAND TOTAL - T&D O&M EXPENSES	**$44,459**	**$44,445**	**$43,704**	**$43,054**

The components of the revisions shown in the table above are discussed below.

<u>Rate Case Update</u>

Hawaiian Electric's Rate Case Update for T&D O&M expense, filed December 4, 2008, revised the Transmission O&M expense test year estimate to $44,446,000, a decrease of $13,000 from the T&D O&M expense test year estimate of $44,459,000 in direct testimony. Settlement Exhibit at 34. The decrease is the net result of revisions to the following specific T&D O&M expense estimates:

- An <u>increase of $409,100</u> . (Transmission: $83,000; Distribution: $325,000) HECO T-8 Rate Case Update, page 9. The increase consists of the following revisions:

- T&D employee additions (Construction and Maintenance): <u>$107,000 increase</u> (Labor). In order to address the substantial workload of the Construction and Maintenance ("C&M") Department, an increase in C&M personnel was needed. As a result, C&M's revised staffing plan added two new positions, namely, a Senior Construction Manager and a Resource Planner. The labor expenses associated with the Senior Construction Manager and the Resource Planner increased the test year T&D O&M expenses by $67,800 and $39,200, respectively. HECO T-8 Rate Case Update at 1. See also HECO T-8 Rate Case Update, Attachment 2.

- Asset Management Group: $221,800 increase (Labor). An additional $221,800 in T&D O&M labor expenses was required to fund the new Asset Management group within the System Operation department. This amount is the portion of the Asset Management group labor expenses attributed to O&M work. The Asset Management group within the System Operation department will consist of five employees and will later transition into a separate department. The positions in this new department include a Manager, two Directors (Director of Energy Delivery Budgets and Director of Asset Programs), and two asset management program managers. The new Asset Management group will be responsible for providing recommendations regarding Energy Delivery's maintenance and replacement of HECO's aging T&D assets. HECO T-8 Rate Case Update at 6-8. See also HECO Rate Case Update, Attachment 2.
- AMI IT Project Management: $80,300 increase (Non-labor). Hawaiian Electric plans to hire a management consultant to help develop the Request For Proposal ("RFP") for the Companies' AMI Meter Data Management System ("MDMS"). The estimated additional non-labor expense (including taxes) is $119,000 and because the consultant will support the AMI project for all the HECO companies, the cost is apportioned among Hawaiian Electric, MECO, and HELCO at 67.5%, 17.5%, and 15%, respectively. HECO T-8 Rate Case Update at 5-6.
- A decrease of $422,000 (Labor) (Transmission: $120,000; Distribution: $302,000) resulting from the labor expense adjustment proposed in HECO T-15 Rate Case Update, Attachment 6, page 5, based on an estimated Hawaiian Electric test year vacancy rate of 2.37%. See HECO T-15 Rate Case Update, Attachment 6 at 1-4 (discussion of the vacancy rate) and 8-9 (calculation of the vacancy rate).

Settlement Agreement

The Stipulated Settlement Agreement dated May 15, 2009 ("Settlement") revised the T&D O&M expense test year estimate to $43,704,000 (Transmission: $13,859,000; Distribution: $29,845,000), a decrease of $742,000 from the T&D O&M expense test year estimate in the Rate Case Update in the amount of $44,446,000, and a decrease of $755,000 from the T&D O&M expense estimate in direct testimony in the amount of $44,459,000. Settlement Exhibit at 36. The decrease is the net result of revisions to the following specific T&D O&M expense estimates as agreed by the Parties in the Settlement:

- Payroll and Benefits: $55,000 decrease (Labor). In its Rate Case Update, the Company proposed a labor adjustment of ($422,000) to T&D O&M expenses based on a vacancy rate of 2.37% in the Rate Case Update. However, based on data provided in response to CA-IR-354, filed on January 29, 2009, supplemented on May 5, 2009, the Company revised its vacancy rate during settlement discussions to 2.68% which translates to an additional adjustment of ($16,000) and ($39,000) to transmission and distribution O&M expenses, respectively, from the Company's prior adjustment in the Rate Case Update. See Settlement, HECO T-15 Attachment 1, Final Settlement. The Consumer Advocate and DOD agreed to the Company's additional T&D labor expense adjustment for purposes of settlement. Settlement Exhibit at 36.
- Abandoned Projects Normalization: $89,000 decrease (Non-labor). The Consumer Advocate proposed a reduction of Hawaiian Electric's abandoned project costs which included an adjustment of ($89,000) to T&D O&M expenses to reflect an average of the actual abandoned projects cost for 2004-2007 (4 year average). See CA T-3, pages 43 to 48. To

settle the issues in this proceeding, the Company accepted the Consumer Advocate's adjustment of ($89,000) to T&D O&M expenses. Settlement Exhibit at 36.

- General Inflation Factor: $187,000 decrease (Non-labor). The Company accepted the Consumer Advocate's and DOD's recommendation to reduce the 2009 non-labor O&M expenses due to the use of the general inflation factor. Thus, transmission and distribution O&M expenses were reduced in the Settlement by $53,000 and $134,000, respectively, as proposed by the Consumer Advocate. See CA-101, Schedule C-16, page 1. Settlement Exhibit at 37.
- Motor Vehicle Fuel Adjustment: $33,000 decrease (Non-labor). The Consumer Advocate and DOD each proposed a reduction of motor vehicle expense. For purposes of settlement, the Parties have agreed to the Company's updated vehicle fuel estimate as provided in the Company's response to CA-IR-387, Attachment 1, reducing transmission and distribution expenses by $11,000 and $22,000, respectively. Settlement Exhibit at 37.
- Advanced Metering Infrastructure (AMI) – Legal and Consulting Services: $253,000 decrease (Non-labor). The T&D O&M test year expense for legal, regulatory, and outside consulting costs for the AMI project, as updated in the HECO T-8 Rate Case Update at 5, and the Company's response to CA-IR-178 at 4, was $507,000. The Consumer Advocate proposed that these outside services costs be removed from the test year and recovered through CEIS, or alternatively, be recovered through a multi-year amortization. See CA-T-3 at 75. The Company accepted the Consumer Advocate's recommendation for a multi-year amortization. A two-year amortization of the AMI outside services costs, based on the Company's anticipated filing of a 2011 test year as proposed in the on-going decoupling

proceeding, Docket No. 2008-0274, reduces T&D O&M expenses by $253,000 ($507,000 ÷ 2). Settlement Exhibit at 37.

- Merit Salary Reduction: <u>$123,000 decrease</u>. Given the current economic environment, and in the interest of reaching a global settlement in this proceeding, the Company proposed to lower the O&M labor expenses for merit employees for 2009 by $532,000. The Consumer Advocate and the DOD agreed to the reduction. The portion of the reduction allocated to Transmission O&M expense is $43,000 and to Distribution O&M expense is $80,000. Settlement Exhibit at 24-25 and 37. <u>See also</u> Settlement HECO T-13 Attachment 1.
- CIS O&M Expenses and Rate Base Impact: <u>$2,000 decrease</u>. After Hawaiian Electric submitted its Rate Case Update, the Company determined that there was little likelihood of completing CIS during the test year. As a result, the test year O&M expenses associated with the new CIS were reversed, while expenses to continue to operate and maintain the existing CIS were added back. The adjustment to Transmission and Distribution O&M expenses netted to a total of ($2,000), from an increase of $52,000 in Transmission expenses and a reduction of $54,000 in Distribution expenses. Settlement Exhibit at 25-27 and 37. <u>See also</u> HECO T-9, Attachment 2, Final Settlement; and response to CA-IR- 396, Attachment 4 at 1-2.

<u>Revised Schedules in Response to Interim D&O</u>

In accordance with the Interim D&O, the Company filed on July 8, 2008 revised schedules and explanations of certain adjustments to the Company's 2009 test year estimates, as required in Sections II.1. and II.2. of the Interim D&O. This resulted in a revised T&D O&M test year expense estimate of $43,053,000 (Transmission: $13,633,000; Distribution: $29,420,000). Revised Schedules, Exhibit 1 at 10; Revised Schedules, Attachment A at 1. This is a decrease of

$650,000 from the T&D O&M Expense amount agreed to by the Parties in the Settlement.

The decrease is the result of a $650,000 reduction of merit employee wage increases. Pursuant to Section II.2.(c) of the ID&O, the Commission required that, for purposes of interim rates, wage levels be restricted to 2007 levels or the most recent actual labor costs filed with the Commission, taking into account the vacancy rate agreed upon by the Parties on pages 22 and 23 of the Settlement. ID&O at 11. To comply with the ID&O, an O&M labor expense adjustment of $2,829,000 was made to reflect the limiting of the 2009 test year merit salary amounts at the 2007 wage levels, and an associated adjustment for payroll taxes of $203,000. Revised Schedules Exhibit 3 at 11. The portion of the adjustment allocated to T&D O&M expense is $650,000 ($226,000 for Transmission and $424,000 for Distribution). Revised Schedules Attachment A at 1. Although the Company made this adjustment for purposes of interim rates, it is the Company's position that merit employee wage rates should not be held at this level in the rates approved in the Final Decision and Order in this proceeding. The Company's position is explained in more detail elsewhere in this Opening Brief.

The Order Approving HECO's Revised Schedules, filed August 3, 2009 ("Order Approving Revised Schedules"), approved the T&D O&M test year expense estimate presented in Hawaiian Electric's Revised Schedules, namely $13,633,000 for Transmission and $29,420,000 for Distribution, for a total T&D O&M test year amount of $43,053,000. Order Approving Revised Schedules at 1; Order Approving Revised Schedules, Exhibit A at 1.

However, as stated above, it is Hawaiian Electric's position that the Final Decision and Order should not limit the 2009 test year merit salary amounts to the 2007 wage levels. Instead, the Final Decision and Order should reflect the actual 2009 test year merit salary increase restoring a portion of the labor costs that were reduced to Transmission and Distribution O&M

labor expenses for the test year. This would result in a total T&D O&M test year expense amount of $43,703,000.

T&D Materials Inventory

The average T&D Materials Inventory presented in direct testimony was $8,211,496. HECO T-8 at 1; HECO-803.

In its ID&O, the Commission stated that, "the record insufficiently addresses how reductions in commodity prices since the initial filing, if true, should be reflected in T&D Materials Inventory costs included in rates" and directed Hawaiian Electric, for interim rates, to "update its T&D Materials Inventory cost to reflect current commodity prices. ID&O, page 12. The Company revised its 2009 T&D materials ending inventory to $8,167,765, based on a 2.6% decrease applied to the 2009 starting year inventory of $8,385,796, which is $43,000 less than that initially forecasted by the Company, prior to the Accounts Payable adjustment. The revised 2009 test year T&D materials inventory average value is $7,976,281, a decrease of $235,215 from the amount of the T&D Materials Inventory presented in direct testimony. The revised figure also includes an Accounts Payable adjustment of ($601,000). Revised Schedules Exhibit 3 at 14-17; Revised Schedules HECO T-8 Attachment 3.

It is Hawaiian Electric's position that the Final Decision and Order should approve a 2009 test year T&D materials inventory average value in the amount of $7,976,281.

3. Commodity Prices

In Section II.2(d) of the Interim Decision & Order, the Commission noted that HECO's proposed increases from 2007 to 2009 in both (i) Transmission and Distribution ("T&D") Materials Inventory costs and (ii) Other Production Maintenance costs were attributed to, among other things, rising commodity prices. The Commission then stated, "Since the July 2008 filing of this testimony, it is the commission's understanding that commodity prices have fallen substantially." ID&O at 12. For interim rates, the Commission directed the Company to update such costs to reflect current commodity prices. The Commission also invited the parties to provide additional testimony on the "appropriateness" of the Company's proposed increases in such costs, given lower current commodity prices. ID&O at 12-13.

As an initial matter, it must be noted that the inherent volatility in commodity prices over the short term – under one year – has led to a misconception that the Company is resisting a continuing downward trend in such prices. To counteract this view, Dan V. Giovanni, Manager of HECO's Power Supply O&M Department, supplied supplemental testimony concerning, among other things, the price index for copper and brass mill shapes. This index rose to a peak of 446.6 in July 2008, but dropped to 277.8 (a 37.8% decline) by February 2009. The index then proceeded to jump to 357.7 by June 2009 – a 28.8% reversal in four months of 2009. HECO ST-7 at 23-24; HECO-S-704. Due to circumstances like these, the Company has wisely chosen to take a "long view" on commodity costs, rather than simply reacting to short-term peaks and valleys.

The T&D and Other Production Maintenance cost estimates are discussed in turn.

T&D Materials Inventory

The Company prepared a new T&D materials inventory forecast for the 2009 test year average inventory and year-ending inventory values, lowering its T&D materials ending inventory from $8,211,496 to $8,167,765, in prompt compliance with the Commission's directive on interim rates. The Company made clear, however, that although the T&D inventory balance is affected by changing commodity prices, it usually changes more slowly than such prices, for two main reasons. First, the Company typically secures long-term (one to three years), fixed-price contracts for key T&D materials. The Company may reasonably decide to enter into long-term contracts to avoid anticipated rises or spikes in price. Second, the T&D inventory balance includes the costs of hundreds of items, with widely varying rates of turnover; as a result, there is an inherent lag on "re-costing" the inventory to current market prices. Revised Schedules Exhibit 3 at 16-17; see also Tr. (Vol. I) at 140-42 (Young) (reiterating the points above). Hawaiian Electric's revision of its test year estimate of T&D materials inventory average value is also discussed T&D O&M section of this Opening Brief.

The forecasting of price trends is often part and parcel of a large for-profit corporation's activities; it can and should be considered a reasonable and appropriate way of cutting costs. But given the structure of its T&D inventory, it is entirely plausible that the Company may arrive at well-reasoned projections of higher long-term T&D commodity prices, and enter into multiyear contracts for such commodities accordingly (to enjoy the low prices of the present), only to see prices fall in the near term (one year or less) due to short-term volatility. See HECO ST-7 at 23-24 (charting such volatility with respect to certain commodity prices). Moreover, the Company may have a full inventory of slow-moving T&D commodities whose prices happen to be falling, leaving the Company no viable opportunity to purchase the commodities at the reduced prices. See Tr. (Vol. II) at 141 (Young) ("[T]here are some materials that don't turn as fast and so their prices would not change necessarily with respect to commodity pricing, because their prices have been fixed at the time that they were purchased and placed into inventory."). Thus, although the Company may use best efforts to lock in low commodity prices with long-term contracts, the vagaries of the commodities market, coupled with the delayed effect of commodity price fluctuations on the T&D inventory balance, can sometimes lead to higher T&D inventory values despite a corresponding short-term decline in commodity prices. This occasional circumstance must not be construed as the product of unreasonable or inappropriate behavior on the part of the Company.

Other Production Maintenance Costs

To comply with the Commission's directive on interim rates, the Company made a $177,000 adjustment to Other Production Maintenance costs, down from the 2009 test year estimate of $8,871,000, thereby offering "an immediate reflection of any commodity pricing decrease that *might* have an impact on . . . fabricated materials costs." Revised Schedules Exhibit 3 at 17, 19 (emphasis added). The Company noted, however, that "[i]t is difficult and impractical to specifically identify the portion of this [Other Production Maintenance] cost that is for raw materials and subject to varying prices for commodities. It is also difficult to establish any specific cost relationship between this material cost and commodity pricing." This difficulty can be traced to the fact that materials used for Other Production Maintenance overwhelmingly consist of fabricated materials – for example, internal assemblies for large pumps, air heater baskets, boiler tubes, valves, turbine bearings and seals, and fittings and connectors – and the cost of commodities used to manufacture such materials represents just a small fraction of the total material cost. Revised Schedules Exhibit 3 at 17-19.

To add clarity to this issue, the Company filed the Supplemental Testimony of Dan V. Giovanni, Manager of HECO's Power Supply O&M Department. Mr. Giovanni stated that the Company considered its original maintenance materials estimate of $8,871,000 to be reasonable and that the Commission's downward adjustment was unwarranted. Four reasons were provided. First, the record from the past four years shows that the Company has historically been conservative and thus very reasonable with its maintenance projections, consistently forecasting well below the actual costs for maintenance materials. The following table summarizes the

Company's repeated under-budgeting in this area:

Materials – Other Production Maintenance ($000)				
	2006	2007	2008	2009
Budget	9,158	7,738	10,352	8,871
Recorded	10,110	9,785	11,528	4,804 (through 5/30/09)
Difference	-952	-2,047	-1,176	4,067

HECO ST-7 at 23.

Second, as mentioned at the outset, commodity prices are subject to severe short-term volatility, which included a sharp increase in price indexes in the months following the "lows" experienced in March 2009. Given such historic fluctuations, the Company made only limited use of monthly updates on commodity market prices, as general points of reference; it never used such data directly in computing its maintenance materials cost estimates for 2009. HECO ST-7 at 23-24, 28; HECO-S-704.

Third, there is no proven correlation between raw material costs and the prices paid by the Company for fabricated materials; thus, it does not make sense to link Other Production Maintenance cost estimates to variations in commodity prices. Although the Company agreed to analyze "what relationship can be made between the current commodity prices and the costs of fabricated materials used for Product Maintenance," Revised Schedules Exhibit 3 at 19, it was ultimately unable to find such a relationship. HECO ST-7 at 24.

Fourth, the Company proactively schedules its maintenance projects to account for variations in the prices of fabricated materials, thereby keeping maintenance costs under control.

Mr. Giovanni observed that "[w]hen prices of fabricated materials are high, it results in work being performed at a cost that exceeds the budget (as it has in previous years) and lower priority discretionary work being deferred. Conversely, in periods when prices for fabricated materials are low[,] it results in more work being performed, including lower priority infrastructure projects that are otherwise deferred." HECO ST-7 at 27; see also HECO response to PUC-IR-153 at 2 (noting that "[i]f actual materials expenses are higher than budgeted for the given year . . . , it is generally compensated for by reduced labor expenses, reduced outside services expenses, reduced maintenance work being performed, or a combination thereof").

Mr. Giovanni lent further support to his supplemental testimony at the panel evidentiary hearing. He made clear that a $2,360,000 increase in production maintenance nonlabor expense from 2007 to 2009 was attributable to a combination of (i) differences in the type of maintenance work performed, resulting in the use of different fabricated materials and/or different designs of certain fabricated materials; and (ii) general inflation. Commodity prices would not be the root cause of the increase, per Mr. Giovanni, they being a "small part of the cost driver." He also indicated that the portion of the nonlabor expense increase attributable to commodity prices is too hard to ascertain, as it is "too mixed in with everything else." Tr. (Vol. I) at 133-36 (Giovanni).

For the reasons set forth above – short-term volatility in commodity prices, historical under-budgeting of maintenance costs, the lack of correlation between commodity costs and fabricated materials costs, and cost containment responses to fabricated materials price variations – the Company's original maintenance materials estimate of $8,871,000 should be considered conservative, well-reasoned, and 88,948

appropriate irrespective of any temporary shifts in commodity price levels. Hawaiian

Electric's revision of its test year estimate of Production Maintenance expense is also discussed in the Production O&M Section of this Opening Brief.

C. CUSTOMER ACCOUNTS AND CUSTOMER SERVICE EXPENSE

1. Customer Accounts Expense

Hawaiian Electric's 2009 test year estimate for Customer Accounts Expense (excluding uncollectibles) is $12,358,000. See Revised Schedules Exhibit 1 at 1.

In Direct Testimony, Hawaiian Electric's 2009 test year Customer Accounts expenses, excluding Allowance for Uncollectible Accounts Expenses, were estimated at $15,954,000. See HECO-901 at 1; HECO T-9 at 4. In the rate case updates, the Company's test year estimate, excluding uncollectible expense, increased to $16,297,000 as shown in HECO T-23 Rate Case Update, Attachment 7. In their direct testimonies, the Consumer Advocate and DOD recommended downward adjustments to the Company's updated estimates of Customer Accounts Expense (excluding uncollectibles) of $3,344,000 and $4,183,000 respectively.[7] See Settlement Exhibit at 39-40.

In settlement, the parties agreed on a 2009 test year Customer Accounts expense total of $12,500,000, excluding uncollectibles. See Settlement Exhibit at 41.

In the Interim D&O, the Commission restricted the Company's merit employee wage levels, for purposes of interim rates, to 2007 wage levels ro the most recent actual labor costs filed with the Commission, taking into account the vacancy rate agreed upon by the parties in the Settlement Agreement. See Interim D&O at 11. As a result, the Company's Revised Schedules reflected a decrease in the test year estimate of Customer Accounts expense (excluding uncollectibles) to $12,358,000. See Revised Schedules Exhibit 1 at 1.

[7] The Consumer Advocate's adjustment included a downward amortization adjustment of $977,000 due to the removal of the CIS project from this rate case. See Settlement Exhibit HECO T-9 Attachment 2.

2. **Uncollectibles**

Hawaiian Electric's 2009 test year Customer Accounts Uncollectibles Expense is $1,302,000. See Settlement Exhibit at 41; Revised Schedules Exhibit 1 at 10; HECO ST-9 at 4-6.

Hawaiian Electric's Direct Testimony and rate case update included a 2009 test year allowance of $1,339,000 for uncollectible accounts expense at current effective rates, based on an uncollectibles factor of 0.0719 percent. See HECO-901; HECO T-9 at 25; HECO T-9 Rate Case Update at 8; Settlement Exhibit at 41.

In settlement, the parties agreed to an uncollectibles expense of $1,302,000. See Settlement Exhibit at 41-42.

In the Interim D&O, the Commission noted "that there appears to be significant increases in certain expenses between the 2007 test year interim award to the 2009 test year in the areas of . . . allowance for uncollectibles. . . . These areas may be subject to further examination by the commission." IDO at 16. In response to this aspect of the Interim D&O, the Company provided supplemental testimony in HELCO ST-9 summarizing the support in the record for the increase in uncollectibles since 2007, as well as more recent data for January through May 2009, demonstrating the reasonableness of the 2009 uncollectibles expense of $1,302,000. See Revised Schedules Exhibit 1 at 10; HECO ST-9 at 4-6; HECO-S-901.

3. **Customer Service Expense**

Hawaiian Electric's 2009 test year estimate of Customer Service Expense is $6,558,000, which is the settlement amount of $5,784,000[8] plus the $774,000 reduction for informational advertising.

In Direct Testimony, the Company proposed a normalized 2009 test year Customer Service Expense of $7,007,000 (see HECO-1001; HECO T-10 at 1), which was increased by $72,000 in the rate case updates to $7,079,000, due to an increase of $72,000 with the addition of the Director, Special Projects to Customer Service Department (see HECO T-10 Rate Case Update at 1, filed December 5, 2008). This was offset by a decrease of $82,000 for a labor adjustment based on a test year vacancy rate of 2.37% (see HECO T-15 Rate Case Update, Attachment 6 at 5, filed December 12, 2008), which adjusted the test year amount to $6,997,000.

In settlement, the parties agreed to a 2009 test year total settlement agreement Customer Service Expense amount of $5,784,000, which included (for purposes of the Interim D&O) the Consumer Advocate's negative adjustment of $774,000 for informational advertising. The subject of informational advertising is further discussed elsewhere in this Opening Brief.

In the Revised Schedules, Hawaiian Electric adjusted the test year Customer Service Expense downward to $5,514,000 (see Revised Schedules Exhibit 1 at 1) reflecting adjustments related to the costs of HCEI-related positions and merit employee wage increases. See Revised Schedules Exhibit 3, Attachment A at 1.

4. Stipulated Settlement Letter

The following is a brief discussion of the agreements reached in the Stipulated Settlement Letter concerning customer accounts and customer service expenses.

Customer Accounts Expense

For purposes of settlement, the parties agreed on the following Customer Accounts

[8] This amount does not include the 2% wage increase that Hawaiian Electric states it is willing to forego in the Results of Operations section of this Opening Brief.

expense adjustments: (1) removal of $3,741,000 in CIS Project expenses from the test year; (2) downward adjustment of $4,000 in connection with a total reduction in O&M expenses of $241,000; (3) additional Customer Accounts labor expense reductions of $25,000 relating to vacancy rate adjustments; and (4) a Customer Accounts labor expense reduction of $27,000 relating to merit salary reductions. See Settlement Exhibit at 41.

Uncollectibles

The Consumer Advocate, in its direct testimony, proposed to adopt the Company's uncollectible ratio to adjust uncollectible expenses for the 2009 test year, so as to correspond with Hawaiian Electric's lower GWh sales volume forecast and the Consumer Advocate's recalculated revenues (CA-T-1, pages 99 to 100). Applying the Company's 0.0719 percent uncollectibles factor to the Consumer Advocate's lower sales revenue estimate yielded a test year uncollectible expense of $951,000. During settlement discussions, Hawaiian Electric provided updated uncollectibles information showing a higher uncollectible expense amount than that proposed by either the Company or the Consumer Advocate. As a compromise of this issue as part of a broader settlement, the Consumer Advocate agreed to effectively return uncollectibles to the amount originally proposed by the Company after taking into account its lower sales forecast. This resulted in a settled-upon uncollectibles expense of $1,302,000. See Settlement Exhibit at 41-42.

Customer Service Expense

The Consumer Advocate's direct testimony proposed three a downward adjustments totaling of $1,325,000, to the Company's updated Customer Service Expense, which resulted in proposed Customer Service Expenses of $5,672,000. The DOD's direct testimony proposed to reduce Customer Service Expense by $230,000. See Settlement Exhibit at 4643.

As a result of the settlement discussions and an additional negative merit salary reduction of ($37,000), the Parties reached agreement on all of the proposed Customer Service adjustments (except for informational advertising, which the Consumer Advocate and the Company agreed would be addressed at the evidentiary hearing). This resulted in a 2009 test year total settlement agreement Customer Service Expense amount of $5,784,000, which included (for purposes of the Interim D&O) the Consumer Advocate's negative adjustment of $774,000 for informational advertising. See Settlement Exhibit at 46.

D. ADMINISTRATIVE AND GENERAL EXPENSE

Hawaiian Electric's 2009 test year estimate for total A&G Expense is $88,948,000. See HECO-S-1101; HECO ST-11 at 2.

In Direct Testimony, Hawaiian Electric's unadjusted estimate ("base case") of total A&G O&M expenses for test year 2009 was $76,708,000. HECO-1101 at 1; HECO T-11 at 2.

In the HECO T-11 Rate Case Update, the Company increased its test year expense estimate by $1,942,000 to $78,650,000. See HECO T-11 Rate Case Update, Attachment 1 at 1. Subsequently, in the HECO T-15 Rate Case Update, as part of the Company's employee headcount reduction and labor expense adjustment total of $(1,729,000), A&G expense was reduced by $534,000 due to the labor expense reduction and was reduced by $397,000 due to the employee benefits reduction (HECO T-15, Attachment 6 at 5). As a result, the updated A&G base case expense amount of $77,719,000 was reflected in HECO T-23 Rate Case Update, Attachments 4, 7 and 8, page 1. See HECO T-23 at 3.

In settlement, the parties agreed to a revised test year A&G expense estimate of $88,948,000, an $11,229,000 increase over the Company's updated estimate of $77,719,000. See Settlement Exhibit at 47-50.

As further discussed elsewhere in this brief, the Interim D&O excluded a number of costs from interim rates, which resulted in various A&G Expenses impacts. See Interim D&O at 7-13. In addition, the Interim D&O invited the submission of additional testimony on increases in among other things, A&G expenses between 2007 and 2009. See Interim D&O at 16.

As a result of the Interim D&O, the Company's Revised Schedules reflected A&G expenses of $87,148,000 (see Revised Schedules Exhibit 1 at 1), reflecting reductions for the removal of costs associated with HCEI-related positions, CT-1 and merit employee wage increases. See Revised Schedules Exhibit 3, Attachment A at 1. In addition, as further discussed elsewhere in this brief, the Company submitted supplemental testimony discussing the reasonableness of the 2009 test year A&G Expenses A&G estimate of $88,948,000 that was used in the settlement agreement. See HECO ST-11; HECO-S-1101.

1. Administrative Expenses

Hawaiian Electric's estimate of Administrative Expenses for the 2009 test year for Accounts 920, 921 and 922 is $30,422,000. See HECO ST-11 at 2. As shown in HECO-S-1101, the estimates, by account, are as follows:

Account	Description	($000)	
920	A&G Expense – Labor	$18,558	
921	A&G Expense – Non Labor	$15,102	
922	A&G Expenses Transferred	($3,238)	
	Total		$30,422

In Direct Testimony, the Company estimated expenses for accounts 920, 921 and 922 of $19,417,000, $15,202,000 and ($3,197,000), respectively. HECO T-11 at 4. In the Rate Case Update, the Company estimated expenses for accounts 920, 921 and 922 of $19,359,000,

$15,445,000 and ($3,212,000), respectively. See HECO T-11 Rate Case Update at 1-7.

As a result of the settlement, the estimates for accounts 920, 921 and 922 were adjusted to $18,558,000, $15,102,000 and ($3,238,000), respectively, resulting in a total Administrative Expenses estimate of $30,422,000. See HECO-SWP-1101 at 1. The Consumer Advocate and DOD are in agreement with Hawaiian Electric's 2009 test year estimate of Administrative Expenses. See Settlement Exhibit at 48-50; HECO-S-1101.

2. Outside Services

Hawaiian Electric's estimate of outside services expense for the 2009 test year for Accounts 923010 and 923020 is $2,666,000. See HECO T-11 at 4; HECO ST-11 at 2. As shown in HECO-S-1101, the estimates, by account, are as follows:

Account	Description	($000)
923010	Outside Services – Legal	$ 131
923020	Outside Services – Other	$2,535
Total		$2,666

The Consumer Advocate and DOD are in agreement with Hawaiian Electric's 2009 test year estimate of Outside Services, which has not changed since the Company filed its Direct Testimony. See HECO T-11 at 4; Settlement Exhibit at 50; HECO-S-1101.

3. Insurance

Hawaiian Electric's 2009 test year insurance expense estimate for Accounts 924 and 925 is $10,229,000. As shown in HECO-S-1101, the estimates, by account, are as follows:

Account	Description	($000)
924	Property Insurance	$3,058
925	Injuries & Damages – Employees	$7,171

Total	$10,229

In Direct Testimony, the Company estimated expenses for accounts 924 and 925 of $3,062,000 and $7,192,000, respectively. See HECO T-11 at 4. As a result of the settlement, the estimates for accounts 924 and 925 were adjusted to $3,058,000 and $7,171,000, respectively. See HECO-S-1101; HECO-SWP-1101 at 1. The Consumer Advocate and DOD are in agreement on the 2009 test year estimate for insurance. See Settlement Exhibit at 47-50.

4. Miscellaneous A&G Expenses

Hawaiian Electric's 2009 test year estimate of Miscellaneous A&G expenses for Accounts 928, 9301, 9302, 931 and 932 is $8,815,000. As shown in HECO-S-1101, the estimates, by account, are as follows:

Account	Description	($000)
928	Regulatory Commission Expenses	$440
9301	Inst. or Goodwill Adv. Expense	$36
9302	Miscellaneous General Expense	$3,376
931	Rents Expense – A&G	$3,426
932	A&G Maintenance	$1,537
Total		$8,815

In Direct Testimony, the Company estimated expenses for accounts 928, 9301, 9302, 931 and 932 of $440,000, $36,000, $3,857,000, $3,062,000 and $1,565,000, respectively. See HECO T-11 at 4, 44. In the rate case update, the Company updated the estimates for accounts 9302, 931 and 932 to $4,304,000, $3,903,000 and $1,685,000, respectively, which resulted in a total updated Miscellaneous A&G Expense estimate of $10,368,000. See HECO T-11 Rate Case Update, Attachment 1 at 1.

As a result of the settlement, the estimates for accounts 928, 9301, 9302, 931 and 932 were adjusted to $440,000, $36,000, $3,376,000, $3,426,000 and $1,537,000, respectively, resulting in a total Miscellaneous A&G expense estimate of $8,815,000. See HECO-S-1101; HECO-SWP-1101 at 1. The Consumer Advocate and DOD are in agreement on the 2009 test year estimate for Miscellaneous A&G Expenses. See Settlement Exhibit at 47-50.

5. Stipulated Settlement Letter

The following is a brief discussion of the agreements reached in the Stipulated Settlement Letter concerning the settlement A&G expense estimate of $88,948,000.

The Consumer Advocate's direct testimony recommended a test year A&G expense estimate of $89,239,000, an increase of $11,520,000 over the Company's updated estimate of $77,719,000, based on the following 11 adjustments:

- an adjustment of ($677,000) to remove A&G R&D expense related to the Oahu Electric System Analysis study;
- an adjustment of ($62,000) to reduce IRP/CESP non-labor expense by normalizing IRP Planning expenses based upon an updated three-year average of actual spending;
- an adjustment of ($257,000) for Payroll & Benefits;
- an adjustment of $14,057,000 to recognize revised actuarial estimates that increased 2009 NPPC and NPBC;
- an adjustment of $2,000 to normalize Abandoned Project Costs;
- an adjustment of ($3,000) to reduce the impact of the general inflation factor from 2.5% to 0.0% in the test year and an adjustment of ($5,000) for vehicle fuel on-cost expense for a total reduction of $8,000. The $5,000 reduction for vehicle fuel was based on the Consumer Advocate's acceptance of the Company's updated vehicle fuel estimate as provided by the Company in response to CA-IR-387, Attachment 1;
- an adjustment of ($581,000) to reduce the office lease expense by allowing only the months in which four new leases would be in effect during 2009;
- an adjustment of ($269,000) to reduce A&G maintenance expense by first removing $145,000 which is to be capitalized in 2009 and then averaging 2006 to 2008 recorded

amounts, and the revised 2009 test year estimate (after the removal of the $145,000) for nonrecurring general plant maintenance expense recorded to A&G expense account 932;

- an adjustment of ($50,000) to disallow certain IFRS consultant fees;
- an adjustment of ($611,000) to remove all AMI R&D costs (provided these costs could be recovered through the REIP/CEIS Surcharge or through a separate AMI surcharge mechanism); and
- an adjustment of ($23,000) to allocate Feed-in Tariff outside services costs between Hawaiian Electric, HELCO and MECO, as provided in the Company's response to CA-IR-343.

<u>See</u> Settlement Exhibit at 48-49.

In its direct testimony, the DOD recommended a test year expense estimate of $76,145,000, a decrease of $1,574,000 from the Company's updated estimate, based on the following eight adjustments:

- an adjustment to A&G expenses of ($114,000) to remove the impact of the test year general inflation factor of 2.5%;
- an adjustment of ($145,000) to reduce A&G maintenance expense for the Ward Base Yard Project;
- an adjustment of ($23,000) to reduce vehicle fuel cost as a result of using current 2009 test year fuel prices as of March 23, 2009;
- an adjustment of ($181,000) to community service activities expense;
- an adjustment of ($297,000) for Work Force Vacancies to A&G O&M expenses based on a 3.3% vacancy rate;
- an adjustment of ($790,000) to normalize A&G R&D expense;
- an adjustment of ($67,000) to reduce by two-thirds Hawaiian Electric's 2009 budget for studying IFRS; and
- an adjustment of ($138,000) to reduce office lease expense.

<u>See</u> Settlement Exhibit at 49-50.

<u>R&D (A&G and Production)</u>

Hawaiian Electric's 2009 test year estimate for Research and Development ("R&D")

Expenses presented in direct testimony was $3,533,000. See HECO T-14 at 19; HECO-1406.

Rate Case Update

In the Company's Rate Case Update for R&D expenses filed on December 2, 2008, the test year expense estimate was revised to $3,980,000, an increase of $447,000 over the expense estimate presented in direct testimony. See HECO T-14 Rate Case Update at 1 and 14. The increase resulted from revisions to the following specific R&D expense estimates:

- Develop and Demonstrate New Technology – AMI: $197,000 increase. The Company increased its test year 2009 estimate for the Advanced Meter Infrastructure ("AMI") R&D project by $197,000 due to the Company's plans to 1) extend the current eMeter contract into the first quarter of 2009, 2) select either eMeter or Itron for Phase 2 testing for the remaining nine months in 2009, and 3) contract with Luminant to continue information technology support. See HECO T-14 Rate Case Update at 1-2; response to CA-IR-158.
- Other Long-Term R&D strategies – Oahu Electric System Analysis: $250,000 increase. The Company increased its test year 2009 estimate for the Oahu Electric System Analysis ("Oahu study") by $275,000 due to the receipt of a rough order-of-magnitude ("ROM") estimate for the Oahu study from General Electric ("GE"), as discussed in the Company's response to CA-IR-161. See HECO T-14 Rate Case Update at 2-3.

In its direct testimony, the Consumer Advocate proposed a downward adjustment of $1,987,000 to Hawaiian Electric's updated R&D expense estimate, reflecting adjustments of ($50,000), ($649,000), ($677,000) and ($611,000) related to the Biofuel Agriculture Crop Research, Biofuel Co-Firing Project, Oahu Electric System Analysis and AMI Project, respectively. The Consumer Advocate proposed that these costs be deferred and recovered through the CEI Surcharge or a separate surcharge mechanism. See CA-T-3 at 68-86; CA-101, Schedule C-4 and C-20. The DOD, in its direct testimony, proposed a downward adjustment of $790,000 to Hawaiian Electric's updated R&D expense estimate based on including a normalized (2006-2008) non-EPRI R&D amount. See DOD-T-1 at pages 36-38; DOD-122.

Settlement

As a result of settlement discussions among the Parties, Hawaiian Electric agreed to reduce its test year estimate for R&D expenses to $3,059,000. See Settlement Exhibit at 51. This is a decrease of $921,000 from the test year estimate for R&D in the Company's Rate Case Update. The increase resulted from revisions to the following specific R&D expense estimates:

- Oahu System Analysis study: $677,000 decrease. In settlement discussions, the Parties agreed that both the HCEI Implementation Studies (aka "Big Wind Studies") and the Oahu Electric System Analysis (CA-101, Schedule C-4, lines 1 and 6) should be recovered through the REIP/CEI Surcharge as proposed in Docket No. 2007-0416. See HECO T-7 Rate Case Update at 2-3. Thus, the Production O&M test year expense estimate was reduced by $2,220,000 for removal of the Big Wind Studies, as discussed in more detail elsewhere in this Opening Brief, and the Miscellaneous A&G test year estimate for R&D expense was reduced by $677,000 for removal of the Oahu Electric System Analysis study. See Settlement Exhibit at 21, 50-51.
- AMI R&D expenses: $244,000 decrease. The Parties agreed in the Settlement to separate the $611,000 included in AMI R&D expenses between outside services of $488,000 and $123,000 for Tower Gateway Base Station lease rental, as set forth in the response to CA-IR-158 at 5. The $488,000 would be amortized over two years and the $123,000 lease rental would remain in R&D test year expenses. Thus, the amount of

AMI R&D expenses included in A&G expenses to remain in base rates is $367,000 ($488,000 ÷ 2 years + $123,000). See Settlement Exhibit at 21-22 and 50-51.

There were no revisions to Hawaiian Electric's test year expense estimate for R&D expenses after the Settlement and the Statement of Probable Entitlement. Therefore, it is Hawaiian Electric's position that the Final Decision and Order should allow expenses for R&D for the 2009 test year in the amount of $3,059,000.

CIS Implementation Costs

The adjustment to A&G O&M expenses is a reduction of $445,000. See Settlement Exhibit at 51.

Integrated Resource Planning/CESP

Hawaiian Electric accepted Consumer Advocate's proposal to reduce test year non-labor expense for IRP/CESP by $62,000 by averaging 2006, 2007 and 2008 recorded amounts, and to apply the entire negative adjustment to A&G O&M expenses. See Settlement Exhibit at 51.

In the Interim D&O, the Commission invited additional testimony regarding the reasonableness of the increase in IRP/DSM costs in the 2009 test year over previous years (see Interim D&O at 15). As further discussed elsewhere in this brief, the Company provided additional testimony regarding its base DSM expenses in HECO ST-10.

Payroll and Benefits (CA-101, Schedule C-13)

The Company proposed a labor adjustment of ($534,000) and a benefits adjustment of ($397,000) to A&G expenses based on a vacancy rate of 2.37% in the Rate Case Update. Both the Consumer Advocate (2.7%) and DOD (3.3%) presented alternative vacancy rate recommendations. However, based on updated data, the Company revised its vacancy rate to 2.68%, which translated to an additional adjustment of ($69,000) to A&G O&M labor expense.

The Consumer Advocate and DOD agreed to the Company's additional payroll adjustment for purposes of settling issues in this proceeding. In addition, based on the revised vacancy rate and the updated employee benefits expenses, the associated reduction to employee benefits expense was $422,000, which resulted in a total reduction of $491,000 (excluding payroll tax effects) to the A&G block of accounts. See Settlement Exhibit at 51-52.

Pension/OPEB Costs and Regulatory Accounting (CA-101, Schedule C-14)

In supplemental responses to DOD-IR-104, the Company updated the pension and postretirement estimates, attributing the amounts for NPPC and NPBC primarily to the reduction in plan assets and a decrease in the expected return component of the NPPC and NPBC. In CA-101, Schedule C-14, line 7, the Consumer Advocate proposed an adjustment of $14,057,000, to recognize the updated 2009 NPPC and NPBC, quantified by Hawaiian Electric's actuarial consultant Watson Wyatt Worldwide. The Consumer Advocate's adjustment included the NPPC and NPBC increases in base rates rather than capturing the pension and OPEB cost increases in the tracking mechanisms for future rate recognition. The Company agreed with the Consumer Advocate's position to include the NPPC and NPBC increases in base rates rather than capturing the pension and OPEB cost increases in the tracking mechanisms for future rate recognition. See Settlement Exhibit at 52.

The Company, however, proposed to correct the Total Other Postretirement Benefits amount by removing an additional $19,000 of the increased executive life program (post retirement) costs to simplify and limit the issues in this rate case. See Settlement Exhibit at 52.

In addition, in order to properly calculate the updated estimate of employee benefit expenses per employee, the Company incorporated the impact of the increased NPPC and NPBC in the Total Employee Benefits amount. The amount of Employee Benefits Charged to O&M

was $37,813,000, which was used to derive the updated employee benefit cost per employee of about $23,000 for the overall labor adjustment. See Settlement Exhibit at 52.

As a result, the Company proposed an adjustment of $14,042,000 to recognize a revised 2009 NPPC and NPBC, which was $15,000 less than the Consumer Advocate's adjustment amount of $14,057,000. See Settlement Exhibit at 53.

In DOD-121, the DOD, proposed a pension expense of $14,623,000, and an OPEB expense of $3,853,000, the same amounts that the Company used in its Direct Testimony, which was mainly for simplicity purposes and also because DOD had concerns regarding the large increase in NPPC. In settlement discussions among the Parties, the following points were reiterated to emphasize the impact of both a declining economy as well as an improving economy. See Settlement Exhibit at 53.

The Company agreed with the Consumer Advocate's recommendation to include the NPPC and NPBC increases in base rates rather than capturing the pension and OPEB cost increases in the tracking mechanisms for future rate recognition, and as such, accepted the Consumer Advocate's proposal, subject to the minor correction noted above. For purposes of a global settlement, the Parties agreed to a pension and OPEB expense adjustment amount of $14,042,000. See Settlement Exhibit at 53.

Abandoned Projects Normalization

Hawaiian Electric's test year estimate as shown in HECO-1119 for abandoned project costs of $172,000 was based on a five-year average of the actual abandoned project costs for 2003-2007. The Consumer Advocate proposed a total reduction of $79,000 to reflect a four-year average of the actual abandoned projects cost for 2004-2007. To settle the issue, the Company accepted the Consumer Advocate's adjustment of $79,000. The portion of the

Abandoned Project Costs adjustment allocated to A&G expense resulted in an increase in expense of $2,000. See Settlement Exhibit at 53-54.

General Inflation Factor and Rev'd Vehicle Fuel Forecast (CA-101, Schedule C-16)

The Company has accepted the Consumer Advocate and DOD's recommendations to reduce the 2009 non-labor O&M expenses due the use of the general inflation factor. Thus, A&G O&M expense was reduced by $3,000, and the general inflation factor and revised vehicle fuel forecast adjustment allocated to A&G expense resulted in a reduction of $8,000. See Settlement Exhibit at 54.

Office Lease

In direct testimony, Hawaiian Electric's test year 2009 estimate for account 931 – rent expense was $3,062,000. HECO T-14 at 14-15; HECO-1405 at 1. The expense estimate included the lease rental expense for office space in Central Pacific Plaza ("CPP"), the King Street building, Pauahi Tower, Waterhouse Building and Honolulu Club, and related common area maintenance expenses, general excise taxes and the annual real property tax credits, where applicable. Additionally, it included the lease rental expense for the Waiau Viaduct space and an allocated usage cost for the ASB Training and Break Rooms. HECO T-14 at 15. The rent expense estimate was revised several times during the course of this proceeding. The revisions are discussed below.

Rate Case Update

In Hawaiian Electric's Rate Case Updated filed December 2, 2008, the test year office lease rent expense was revised to $3,903,000, an increase of $841,000 over the rent expense estimate presented in direct testimony. HECO T-14 Rate Case Update at 1, 6 and 12-13. The increase in office rent expense was due to additional office spaces required for the additional staffing resulting from: 1) Energy Agreement initiatives which required additional staffing and new organizations in several departments, 2) additional staffing and new groups for other organizational changes not related to the Energy Agreement initiatives, 3) relocation of the Meter Engineering Division due to a water incursion problem in the basement of the Ward I Building, and 4) reassessing space requirements of other divisions due to growth. Additional office spaces were needed for offices, work stations, reception areas, conference rooms, training rooms, equipment and supplies storage area, and for certain groups, space to operate and test equipment and machinery. HECO T-14 Rate Case Update at 3-74. The total additional office space of the following four leases is 24,307 square feet and had the following impact on the test year estimate for office lease rent expenses:

	Annual Lease
Rent	
• Waterhouse Lease for 770 Kapiolani Blvd, Suites 105 and 106	$ 57,000
• ASB Tower Lease for 1001 Bishop Street, Suites 2970 and 2959	470,000
• CPP Lease for 220 South King Street, Suites 600, 650, and 680	255,000
• Waterhouse Lease for 770 Kapiolani Blvd, Suites 401, 402 and 403	59,000
	Total increase in
Miscellaneous General Expenses $841,000	

HECO T-14 Rate Case Update at 6-7.

Response to Consumer Advocate's Information Requests

Hawaiian Electric's response to CA-IR-344 revised the test year office lease rent expense estimate to $3,844,000, a decrease of $59,000 from the Rate Case Update figure of $3,903,000. The revision resulted from an adjustment to include the estimated real property tax credits for the four new leases identified in the HECO T-14 Rate Case Update, totaling to $59,000. Response to CA-IR-344.

Hawaiian Electric revised its response to CA-IR-344 on March 31, 2009 and revised the test year office lease rent expense estimate to $3,765,000, a decrease of $79,000 from the original response to CA-IR-344. See also response to CA-IR-344, Attachment 2 at 1. The Company's response to CA-IR-344 was revised due recent organizational changes, as well as the formulation of a preliminary plan to accommodate staffing changes due to the four needs identified in the HECO T-14 Rate Case Update at 3-7. The changes to the leases and the corresponding impact on rent expense is summarized below:

- Remove: ASB Tower suites 2970 and 2959 $(438,000)

• Remove: CPP suites 600, 650 and 680	(237,000)
• Add: Cooke Street suites 445 and 461	251,000
• Add: CPP 21st floor	267,000
• Remove: ASB Tower allocated training rooms	(76,000)
• Add ASB Tower 8th floor training rooms	154,000
Total decrease in Miscellaneous General Expenses	$(79,000)

Response to CA-IR-344 (Revised 3/31/09).

Settlement

As a result of settlement discussions among the Parties, Hawaiian Electric's rent expense estimate was reduced to $3,426,000, a decrease of $477,000 from the test year estimate in the HECO T-14 Rate Case Update, and a decrease of $339,000 from the rent expense estimate as revised in the response to CA-IR-344 (3/31/09).

The Consumer Advocate proposed to reduce test year office lease expense by $581,000, from the test year estimate in the HECO T-14 Rate Case Update, by disallowing the annualization of new leases executed or expected to be executed during the test year, and by including only those months in which the four new leases' payments would be in effect during the 2009 test year. CA-T-3 at 53-60; CA-101, Schedule C-17.

The Parties agreed to accept the Consumer Advocate's inclusion of only those months in which the four new leases' payments would be in effect during the test year, but to reflect the lease rent rates for the four new leases as shown in the Company's revised response to CA-IR-344, Attachment 2 (3/31/09) for the Waterhouse 105/106, Waterhouse 401/402/403, 445/461 Cooke Street, and CPP 21st Floor leases. This reduced the test year office lease expense update estimate by $477,000. Settlement Exhibit 1 at 54; Settlement HECO T-14, Attachment 2.

Response to Commission Information Request

In response to PUC-IR-126, Hawaiian Electric provided an update to the status of the four leases in the 2009 test year rate case estimates amounting to $288,000 as follows: $18,000 for Waterhouse Suites 105 and 106; $55,000 for Waterhouse Suites 401, 402 and 403; $126,000 for 445/461 Cooke Street; and $89,000 for Central Pacific Plaza 21st floor. See also Final Settlement HECO T-14 Attachment 2, column (E) (Confidential).

- Waterhouse 105/106 – lease signed on 8/15/08 but the Company is currently not paying lease rent due to existing tenants still occupying space. The Company was negotiating to exchange suites 105/106 (combined 2,000 sq. ft.) for suites 110 (3,817 sq. ft.) and 111/113 (2,256 sq. ft.).
- 445/461 Cooke Street – The Company decided not to enter lease agreement due to due to budget constraints in June 2009.
- CPP 21st floor – The Company decided not to enter lease agreement due to budget constraints in June 2009.
- Waterhouse 401/402/403 – This space is occupied as original planned.

During the hearing, questions were raised as to whether Hawaiian Electric should adjust the $288,000 included in the test year estimate for office lease rent expenses for those leases which the Company did not enter into or was not paying lease rent. Tr. (Vol. I) at 224-235. In its closing statement, the Company stated it would make an adjustment to reflect the latest information on office leases. Tr (Vol VIII) at 1380-1381 (Williams). The table below summarizes the net reduction adjustment of $244,000:

LEASE	STATUS	ADJUSTMENT
445/461 COOKE STREET	DID NOT SIGN LEASE DUE TO BUDGET CONSTRAINTS	($125,000)
CPP 21ST FLOOR	DID NOT SIGN LEASE DUE TO BUDGET CONSTRAINTS	($89,000)
WATERHOUSE 105/106	LEASE SIGNED BUT NOT INCURRING LEASE RENT DUE TO EXISTING TENANT STILL OCCUPYING SPACE. ALSO RENEGOTIATING WITH LANDLORD FOR A LARGER SPACE IN SAME BUILDING.	($18,000)

CPP SUITE 1050	LEASE SIGNED AUGUST 28, 2009 AND FILED AS ATTACHMENT 2 TO PUC-IR-126.	$8,000
TOTAL ADJUSTMENT		($224,000)

With the above adjustment, the test year lease rent expense is adjusted from the settlement amount of $3,426,000 to $3,202,000.

A&G Maintenance

The Consumer Advocate proposed to reduce HECO's test year A&G maintenance expense of $1,685,000 (Update HECO T-14 page 19) by $269,000, which represents an adjustment to HECO's non-recurring A&G maintenance expenses. The Consumer Advocate proposed to calculate non-recurring maintenance expenses by normalizing 2006 to 2008 recorded and the 2009 estimate which was adjusted for $145,000 of costs to be capitalized (CA-IR-348 response, part a). The DOD proposed to reduce HECO's test year A&G non-recurring maintenance expense update amount by $145,000 of costs to be capitalized. See Settlement Exhibit at 54.

During settlement discussions, Hawaiian Electric offered to (1) use the same methodology (using an average of 2008-2010 expenses) in calculating its non-recurring maintenance expense for the test year, and (2) remove the $145,000 of costs to be capitalized, which resulted in a net reduction of $145,000. For purposes of settlement only, the Consumer Advocate accepted the Company's offer and agreed to a reduction of $145,000. This resulted in a test year estimate for non-recurring maintenance expenses of $824,000, and a total A&G maintenance expense estimate of $1,537,000, for settlement purposes, which the DOD accepted. See Settlement Exhibit at 55.

IFRS Consultant Costs

With the issuance by the SEC of a proposed "Roadmap" to phase in a mandatory transition from U.S. GAAP to IFRS, the Company projected in its rate case updates $100,000 of consultant costs to begin the conversion process to IFRS. The Consumer Advocate proposed to reduce the IFRS consultant costs by $50,000 to reflect, in part, an allocation of costs to HELCO and MECO and to recognize that the conversion may not proceed on the announced expedited schedule. The DOD proposed to reduce the IFRS consultant cost by $67,000, or two-thirds of the cost. To settle the issue in this proceeding, the Company and DOD accepted the Consumer Advocate's adjustment of $50,000. See Settlement Exhibit at 55.

FIT Consultant Costs Adjustment

The Consumer Advocate proposed to reduce the FIT consultant costs by $23,000, for the portion of the costs for HELCO and MECO. The parties agrees with the Consumer Advocate's proposal of a reduction of $23,000 to the test year. See Settlement Exhibit at 55.

Merit Salary Reduction

The merit salary reduction adjustment allocated to A&G O&M expense is a reduction of $218,000, as further discussed above. See Settlement Exhibit at 56.

Community Services Expense

The DOD questioned whether community service activities expenses are necessary for the provision of safe and reliable electric services, and whether such activities tend to promote goodwill for the Company and enhance its image in the community, and thus proposed a negative adjustment of $181,000 to community service activities expense by allowing only 50% of the test year estimate. The Consumer Advocate has not taken a position in this issue. Hawaiian Electric disagreed with the DOD's position, and proposed not to reduce the test year amount of $361,000. For purposes of settlement only, the DOD agreed to the Company's test year amount of $361,000. See Settlement Exhibit at 56.

6. **Ellipse 6 Upgrade**

In direct testimony, Hawaiian Electric included in A&G expenses costs associated with a periodic upgrade of the Company's core business system, Ellipse, to Ellipse 6 by the end of 2009. The costs included $362,000 in Account No. 921 (A&G Expense – Nonlabor) for software associated with the upgrade (see HECO T-11 at 19, 21-22; HECO-S-1103 at 4), and $1,145,000 in Account No. 923020 (Outside Services – Other) for consultant costs associated with the upgrade (see HECO T-11 at 35-36; HECO-S-1103 at 6).

As discussed in the Company's response to PUC-IR-167, Hawaiian Electric did not normalize the costs estimated for 2009 for the Ellipse 6 upgrade for ratemaking purposes because of the previous method for determining test year expense estimates related to costs for the Ellipse system. Hawaiian Electric would not oppose normalizing the cost of a software upgrade if all of the related costs were considered and the amortization period were based on the time period between rate cases. For the Ellipse 6 project, the costs for both 2009 and 2010 should be considered in determining the normalization amount. Further, if a rate case occurs between upgrades, the normalized cost of the upgrade should be considered in the test year expenses, even if the actual costs would not be incurred in the test year. In that way, the Company would have a reasonable opportunity to recover all the prudent costs of necessary software upgrades (as opposed to only those costs that happen to be incurred during the test year). See Tr. (Vol. I) at 170-74 (Nanbu). Allowing such recovery would be consistent with the principles of ratemaking that (1) the arbitrariness of the 12-month calendar year should not serve to bar a utility from recovering its prudently incurred costs, and (2) regulators should avoid violating the integrity of the test year by approving only cost increases and not taking into account cost decreases. See Tr. (Vol. I) at 179 (Hempling).

Hawaiian Electric completed an upgrade planning study to identify the enhancements Ellipse 6 offered, conducted an Ellipse lifecycle review and confirmed a support timeline for Ellipse 6 in June 2009. However, the Company made a decision not to undertake the Ellipse 6 upgrade projects at this time, and has instead deferred the upgrade to 2011. See Tr. (Vol. III) at 1380 (closing argument). Nevertheless, Hawaiian Electric incurred approximately $212,000 for non-labor costs related to the upgrade planning study, and, as a result of not upgrading to Ellipse 6, will need to incur consulting costs from Mincom, Inc. (estimated at $107,800) to address certain customization issues with the current version of Ellipse, primarily in the payroll register and time and attendance tracking. These issues would have been addressed with the Ellipse 6 upgrade. Response to PUC-IR-167.

As a result of deferring the Ellipse 6 upgrade project, Hawaiian Electric has not incurred the full $1,145,000 for consultant fees in the 2009 test year. Also, due to the deferral of the Ellipse 6 upgrade, software costs for the Ellipse 6 in the test year estimates in Account No. 921 of $362,000 will not be incurred. Response to PUC-IR-167. As stated in this brief, the Company is willing to reflect a downward adjustment to Outside Services – Other (account no. 923020) of $825,000 for consultant costs and A&G Expense-Nonlabor (account no. 921) of $362,000 for software costs that were included in the test year estimate but were not incurred during the 2009 test year. Reducing the O&M expenses by $1,187,000 would reduce the revenue requirement by about $1,300,000. Tr. (Vol. VIII) at 1380 (closing argument).

E. **EMPLOYEE BENEFITS**

1. **Introduction**

Hawaiian Electric's 2009 test year estimate of Employee Benefits expense for accounts 926000, 926010 and 926020 is $36,817,000. As shown in HECO-S-1101, the estimates, by account, are as follows:

Account	Description	($000)
926000	Employee Pensions and Benefits	$40,759
926010	Employee Benefits – Flex Credits	$12,179
926020	Employee Benefits Transfer	($15,302)
926010	Benefits Adjustments	($819)
Total		$36,817

2. Employee Count

Hawaiian Electric's 2009 test year average employee count is 1,601. In Direct Testimony, the Hawaiian Electric's total average number of employees for the 2009 test year was estimated at 1,621. See HECO-1503; HECO T-15 at 3. In the rate case updates, the Company: (1) updated its test year employee count to 1,636; and (2) proposed a $1,729,000 test year expense reduction based on a 2.37% vacancy rate for the Company (excluding the Power Supply process area). See HECO T-15 Rate Case Update; Settlement Exhibit at 22. In settlement, Hawaiian Electric agreed to reduce its employee count by 35, to 1,601. See Settlement Exhibit, HECO T-15, Attachment 1 at 1.

In the Interim D&O, the Commission directed the Company to exclude the costs of a number of HCEI-related positions from interim rates. See Interim D&O at 8-9. Accordingly, in the Revised Schedules, Hawaiian Electric removed $697,000 of O&M labor costs and related adjustments to employee benefits expense of $303,000 and payroll taxes of $51,000 associated with 13 positions that the Company added to the 2009 test year in its rate case update. While the Company complied with the Interim D&O, Hawaiian Electric believes that the removal of these expenses is not justified and seeks to include them in the revenue requirement for the rates approved in a final decision and order. HECO ST-15 at 12.

The Interim D&O also invited additional testimony regarding the reasonableness of the increase in the number of Hawaiian Electric's employees between 2007 and 2009, which the Company provided in HECO ST-15, as further discussed elsewhere in this brief.

3. Stipulated Settlement Letter

The Consumer Advocate, in its direct testimony, expressed reservations with the Company's 2.37% vacancy rate and related regression results, and proposed a 2.7% vacancy rate representing a midpoint range between the Consumer Advocate's calculation of the 2008 vacancy rate of 3.06% and the Company's estimate of 2.37%. The Consumer Advocate also proposed excluding only the Maintenance Division of the Power Supply Department from the employee counts, rather than the entire Power Supply process area. The Consumer Advocate's proposal translated to a reduction of $2,645,000 in total labor expense, payroll tax, and employee benefits adjustments from the test year and represented an additional $916,000 reduction from the Company's initial labor adjustment. See Settlement Exhibit at 22.

The DOD proposed a vacancy rate of 3.3 percent, based on a review of the average quarterly 3.35% vacancy rate for 2008 and the average vacancy rate of all data points from June 30, 2007 through October 31, 2008 of 3.27%. This translated to a labor expense, payroll tax, and employee benefits reduction to the test year of $2,414,000 for the Company, excluding the Power Supply process area. See Settlement Exhibit at 22-23.

For purposes of settlement, the Company proposed a 2.68% vacancy rate, excluding the Operating Division as well as the Maintenance Division of the Power Supply process area, which the other parties accepted for purposes of settlement. The results of Hawaiian Electric's revised vacancy rate estimate translated to a total labor adjustment of $2,521,000, $792,000 more than the Company's initial estimate. See Settlement Exhibit at 23.

F. DEPRECIATION AND AMORTIZATION

Hawaiian Electric's 2009 test year estimate for Depreciation and Amortization expense is $81,868,000. See Settlement Exhibit at 61; HECO-S-1403 at 1; Revised Schedules Exhibit 1 at 1.

In Direct Testimony, the Hawaiian Electric's 2009 test year estimate for depreciation expense was $83,183,000. See HECO-1408; HECO T-14 at 50. In the rate case updates, the Company revised its estimate for plant additions for 2008 and decreased its depreciation expense estimate by $217,000 to $82,966,000. See HECO T-14 Rate Case Update at 1, 9, 15.

In its direct testimony, the Consumer Advocate proposed a downward adjustment of $2,197,000 to Hawaiian Electric's updated Depreciation and Amortization expense estimate, reflecting: (1) an adjustment of -$273,000 due to the use of recorded December 31, 2008 balances; and (2) an adjustment of -$1,924,000 due to the expiration of vintage amortization in September 2009. See CA-T-3 at pages 86 to 89; CA-101, Schedule C-22; and Settlement Exhibit 1 at 59. The DOD, in its direct testimony, proposed a downward adjustment of $3,023,000, reflecting: (1) an adjustment of -$2,198,000 using recorded December 31, 2008 balances; and (2) an adjustment of -$825,000 to reschedule a vintage amortization that was expiring in 2009. See DOD T-1 at pages 24 to 25; DOD-116; and Settlement Exhibit at 59.

In settlement, the parties agreed to accept a counter-proposal by Hawaiian Electric of (1) an adjustment of -$273,000 from using actual recorded 2008 year-end plant in service balances, and (2) an adjustment of -$825,000 to "additional amortization – net unrecovered" expense by amortizing the expired amortization amount over two years until the Company's next rate case in 2011, which resulted in an agreed-upon 2009 test year Depreciation and Amortization expense of

$81,868,000. See Settlement Exhibit at 60-61.

No changes were made to the settled-upon Depreciation and Amortization expense in the Revised Schedules. See Revised Schedules Exhibit 1 at 1.

G. TAXES

1. Taxes Other Than Income Taxes

The taxes included in Taxes Other Than Income Taxes are payroll taxes for (1) the Federal Insurance Contribution Act and Medicare ("FICA/Medicare") taxes, (2) the Federal Unemployment ("FUTA") tax and (3) the State Unemployment ("SUTA") tax, as well as revenue taxes consisting of (4) the State Public Service Company ("PSC") tax, (5) the State Public Utility ("PUC") fee and (6) the County Franchise Royalty ("Franchise") tax. See HECO T-16 at 3.

Hawaiian Electric's 2009 test year estimate of Taxes Other Than Income Taxes at current effective rates and proposed rates are as follows:

TAXES OTHER THAN INCOME TAXES
($ THOUSANDS)
SETTLEMENT

	AT CURRENT EFFECTIVE RATES	AT PROPOSED RATES
PSC TAX	$76,179	$80,876
PUBLIC UTILITY FEE	6,472	6,871
FRANCHISE TAX	32,258	34,250
PAYROLL TAX	7,194	7,194
TOTAL	$122,103	$129,191

S See Statement of Probable Entitlement dated May 15, 2009, Exhibit 1 at 6; Settlement Exhibit at 64; Statement of Probable Entitlement dated May 18, 2009, Exhibit 1 at 6.

In Direct Testimony and the rate case update, the Company proposed test year estimates for Taxes Other Than Income Taxes at current effective rates and proposed rates, as follows:

Taxes Other Than Income Taxes ($ thousands)				
	Direct		Rate Case Update	
	At Current Effective Rates	At Proposed Rates	At Current Effective Rates	At Proposed Rates
PSC Tax	$109,781	$114,791	$109,749	$115,081
Public Utility Fee	9,327	9,753	9,324	9,777
Franchise Tax	46,524	48,649	46,510	48,772
Payroll Tax	7,333	7,333	7,284	7,284
Total	$172,965	$180,526	$172,867	$180,914

See HECO-WP-2303 at 6; HECO T-23 Rate Case Update, Attachment 7 at 6.

The Consumer Advocate's direct testimony recommended reductions to the Company's updated revenue tax estimate of: (1) $4,484,000, to correspond with the proposed downward adjustment to revenues due to the reduced sales forecast; and (2) $42,432,000, to correspond with the proposed adjustment to fuel and purchased energy expenses, which affects test year ECAC revenues. In addition, the Consumer Advocate proposed reductions to the Company's payroll tax of: (1) $18,000, to remove CIS-related costs; and (2) $55,000, to adjust for the vacancy rate adjustment. See Settlement Exhibit at 63. The DOD's direct testimony recommended reductions to the Company's updated payroll tax of: (1) $18,000, to remove costs related to the CIS; and (2) $16,000, related to the FUTA surtax extension. (However, DOD agreed to withdraw the FUTA surtax adjustment, as it resulted from misinterpretation of an IR response and was immaterial to the Company's revenue requirement.) See Settlement Exhibit at 63. The Taxes Other Than Income Taxes agreed upon by the parties in settlement are shown above.

As a result of adjustments made for purposes of the Interim D&O, the Company's Revised Schedules reflect Taxes Other Than Income Taxes at current effective rates and proposed rates of $121,897,000 and $127,323,000, respectively. See Revised Schedules Exhibit 1 at 1.

2. **Income Taxes**

The income tax calculation is based on the "short form" method that has consistently been used in previous Hawaiian Electric rate cases. The Commission has consistently approved test year revenue requirements in previous rate cases, in which this method was used to compute income tax expense, including Decision and Order No. 24171, issued May 1, 2008 in Hawaiian Electric's 2005 test year rate case, Docket No. 04-0113. The "short form" method simplifies the calculation of income tax expense by utilizing net operating income before income taxes, with certain adjustments explained below. The resulting amount is taxable income for ratemaking purposes. Taxable income for ratemaking purposes is multiplied by the composite federal/state income tax rate of 38.9097744 See HECO T-16 at 9-10. This product is then adjusted by the tax effect of income tax items tht have only a federal income tax effect. The two items are the domestic production activities deduction (DPAD) and the preferred stock dividend deduction. These adjustments to tax expense are necessary because the Company's revenue requirements model utilizes the composite federal/state income tax rate in calculating income tax expense (as opposed to separate federal and state income tax calculations). See HECO T-16 at 12-15.

In Direct Testimony, the Company proposed test year estimates for Income Taxes at current effective rates and proposed rates of $22,648,000 and $52,589,000 respectively. See HECO-2303 at 1. In the rate case updates, the Company updated its estimates for Income Taxes at current effective rates and proposed rates to $20,743 and $52,864, respectively. See HECO T-23 Rate Case Update, Attachment 7 at 1.

R&D Credit

Hawaiian Electric's rate case update excluded the R&D credit in its income tax calculations. In their direct testimonies, the Consumer Advocate and DOD proposed an adjustment of a negative $215,000 to include the R&D credit in income taxes. Upon further review, the Company changed its position and recommended inclusion of the R&D credit in the test year computation of income taxes, which decreased income tax expense by $215,000. See Settlement Exhibit at 64.

Interest Synchronization

In D&O 24171, issued in Hawaiian Electric's 2005 test year rate case, the Commission adopted the interest synchronization method in determining the interest expense deduction in the income tax calculations. In their direct testimonies, the Consumer Advocate and DOD calculated the interest expense deduction utilizing the interest synchronization method. Interest synchronization calculations are based on the average rate base and weighted cost of debt. To the extent that the average rate base proposed by the Consumer Advocate and DOD was different from the average rate base included in the Company's rate case update, the Consumer Advocate's and DOD's interest deductions differed from the Company's deduction, resulting in a different income tax expense. See Settlement Exhibit at 64-64.

Settlement

In settlement, the parties agreed that income taxes would be recalculated to recognize adjusted revenues, expenses and synchronized interest (rate base and cost of capital), integrating the results of all adjustments agreed upon by the parties. The resulting test year income taxes at current effective and proposed rates would be the agreed upon amounts in settlement. See Settlement Exhibit at 65. The Statement of Probable Entitlement dated May 18, 2009 proposed an interim increase amount of $79,811,000 which is lower by $9,000 than the amount in the Stipulated Settlement Letter dated May 15, 2009 due to finalization of the revenue requirement run. The resulting test year income taxes at current effective and proposed rates as agreed upon on in this Statement of Probable Entitlement are $15,909,000 and $44,205,000, respectively. See Statement of Probable Entitlement dated May 18, 2009, Exhibit 1 at 1.

Revised Schedules

As a result of the adjustments required pursuant to the Interim D&O, the Company recalculated income taxes for purposes of interim rates. As shown in the Revised Schedules, Hawaiian Electric's Income Taxes at current effective rates and proposed rates are $19,331,000 and $40,993,000, respectively. See Revised Schedules Exhibit 1 at 1.

H. OTHER EXPENSE ISSUES

1. Informational Advertising

Hawaiian Electric's proposed 2009 test year Informational Advertising expense of $1,148,000 includes television, radio and print advertising and collateral materials to more aggressively inform customers about energy information, including educating the public about and gaining their support for the investments needed to help achieve the State's RPS law and other clean energy requirements, as well as to build lasting changes in attitude and behavior regarding efficiency and conservation. Tr. (Vol. V) at 877-878 (Unemori). The estimated expenses include labor costs of $32,000 and non-labor costs of $1,116,000. HECO T-10 at 52; HECO RT-10A at 2; HECO-1003.

The Consumer Advocate proposed to reduce test year informational advertising expense by $774,000, noting that the Commission denied the Company's request to continue the Residential Customer Energy Awareness ("RCEA") Program in its order regarding continuation of the RCEA Program. The $774,000 adjustment was derived by averaging utility (non-DSM) advertising using the 2006, 2007, and 2008 recorded amounts (CA-IR-416 at 2, utility advertising line). At a return on common equity of 11.0%, the revenue requirement value of the $774,000 adjustment is $848,000. HECO RT-1 at 5, 46-55; HECO RT-10A at 2; CA-T-1 at 114-18; CA-101, Schedule C-21.

During settlement discussions, the Parties were not able to reach agreement regarding the proposed amount for informational advertising. The Consumer Advocate and the Company agreed in the Settlement Letter dated May 15, 2009 that this issue should be addressed at the evidentiary hearing, allowing the Commission an opportunity to consider and decide this issue. *See* Settlement Exhibit at 45. For the purposes of the interim decision and order, the Consumer Advocate and the Company agreed to reflect the Consumer Advocate's proposed reduction of $774,000. *Id.* On October 12, 2009, the Commission identified informational advertising as one of the issues that would be covered in its panel hearing. *See* Letter from Commission to Parties dated October 12, 2009. The panel hearing on informational advertising, Panel 12, was held on October 30, 2009.

a. There is a Need for Informational Advertising

(i) The Company's Customers Need Information regarding Energy Conservation

It is critical for the Company to have sufficient resources to continue to widely and consistently share key energy information with its customers. Keeping them informed is especially important given the urgent need for Hawaii to reduce its dependence on fossil fuel and the unprecedented, ambitious and critically important requirements of Hawaii's laws. Tr. (Vol. V) at 873-74 (Unemori) and 934 (Hee). As a public utility, Hawaiian Electric has a continuing responsibility to help inform its customers by providing them energy information and, more broadly, gaining their support for the achievement of the state's energy policy. Having informed consumers who know and embrace their role is a critical element in the transition to a clean energy future. Tr. (Vol. V) at 876-77 (Unemori) and 930, 934 (Hee); HECO's response to CA-IR-125.

Informational advertising assists the Company in: (1) supporting the state's energy policy; (2) working to achieve aggressive renewable portfolio standards that the utility is required by law to meet; (3) helping meet the state's greenhouse gas reduction goals; and (4) helping fulfill the Company's fundamental obligation to provide energy information to its customers, both a bigger picture context and practical steps to help each customer better manage their energy costs. HECO T-10 at 54; HECO RT-1 at 47-48 and 53; HECO RT-10A at 15; Tr. (Vol. V) at 875 (Unemori); HECO's responses to CA-IR-125 and CA-IR-402.

Another reason for the Company's informational advertising is that customers expect to receive such energy information from their utility. Tr. (Vol. V) at 877, 913 (Unemori); HECO's responses to CA-IR-335 at 1; CA-IR-401 at 1. It also sends a very powerful message when the utility itself is asking its customers to use less of its product and use it more efficiently. Tr. (Vol. V) at 878 (Unemori). As a policy matter, the importance of grass roots consumer education efforts is supported by the National Action Plan for Energy Efficiency, sponsored by the U.S. Department of Energy and the Environmental Protection Agency. National Action Plan for Energy Efficiency (dated 2006 and last updated 2008) at 6 – 10; HECO RT-10A at 12-13; Tr. (Vol. V) at 881 (Unemori).

Furthermore, the Hawaii Clean Energy Initiative to which Hawaiian Electric explicitly committed support by signing the Energy Agreement with the State of Hawaii establishes an overall goal of seventy percent clean energy for electricity and ground transportation by 2030. HECO RT-1 at 49.[9]

[9] In addition, the importance of educating the public on the broader issues necessary to achieve this clean energy future was recognized by the HECO and the Consumer Advocate under the "Telling the Energy

b. Informational Advertising Helps the Company Meet Its Statutory Obligations

The Company must achieve the required goals under the Renewable Portfolio Standards law, as well as those promulgated by the State of Hawaii Global Warming Solutions Act of 2007 and the Hawaii Clean Energy Initiative, and HB 1464, passed in the 2009 Session of the State Legislature which establishes an Energy Efficiency Portfolio Standard of 4,300 GWH by 2030. As a regulated public electric utility, Hawaiian Electric has a fundamental responsibility to play a leadership role in helping achieve these statutory objectives as well as an obligation to provide such information to assist customers in managing their energy costs, an expectation that is even greater during this time of rising fossil fuel prices. HECO T-10 at 54; HECO RT-1 at 47-48 and 53; HECO's responses to CA-IR-125 and CA-IR-402.

Such education also directly supports the State's Energy Policy, which provides that it is state policy to, "Promote cost-effective conservation of power and fuel supplies through measures including: (A) Development of cost-effective demand-side management programs; (B) Education; and (C) Adoption of energy-efficient practices and technologies." HRS §226-18; HECO T-10 at 54 and HECO RT-1 at 47-48.

State law holds the Company accountable to meet the Renewable Portfolio Standards ("RPS") promulgated to implement state energy policy. *See* HRS §269-92 and HB 1464 from the 2009 Legislature, which significantly increases the mandated RPS requirements. The current RPS includes the impacts of energy savings from energy efficiency measures through the year 2014 (HB1464). HECO RT-1 at 48; Tr. (Vol. V) at 875 (Unemori); HECO's response to CA-IR-

Story" section of the Energy Agreement as follows: "To maximize public awareness and understanding of this big picture, the communications campaign should utilize a full range of community vehicles, including utility advertising, free media and person-to-person communications with interested groups. Resources for such communications should be authorized and recoverable." HECO's response to CA-IR-402.

125. Furthermore, the Company could be subject to penalties if it fails to meet the RPS standards. "Decision and Order Relating to RPS Penalties" issued December 19, 2008 in Docket No. 2007-0008; HECO RT-1 at 48-49.

Additionally, the law requires a statewide reduction of greenhouse gas (GHG) emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. HRS § 342B-71. When the Director of the Hawaii Department of Health adopts rules establishing emission limits for specific sources or categories of sources of emissions, it seems highly likely, given its public utility franchise role, that when these rules are adopted, Hawaiian Electric will be given major responsibility for lowering GHG emissions for the electricity sector. By far the most cost effective means to reduce GHG emissions is to implement energy efficiency. HRS § 342B-72; HECO T-10 at 54-55; HECO RT-1 at 49; Tr. (Vol. V) at 875 (Unemori).

The planned advertising helps carry out the State's objectives by increasing awareness of the importance of energy conservation from the standpoint of consumer savings and environmental benefits. The messages reinforce the importance of conservation by promoting specific action steps customers can take to achieve conservation. HECO T-10 at 54-55.

c. The Need for Informational Advertising has Previously Been Recognized by the Commission and the Consumer Advocate

The Commission has previously recognized the importance of the Company's efforts to educate its customers about energy matters, including conservation. Docket No. 03-0142, Decision and Order No. 21756, issued April 20, 2005, at 9 to 10; HECO RT-10A at 8. In addition, the Consumer Advocate has previously taken a position suggesting that the Company is expected to provide ongoing information to help customers better manage electricity consumption. Docket No. 2008-0074, Consumer Advocate's Statement of Position at page 28;

HECO RT-10A at 8.

The importance of education, previously recognized by both the Commission and the Consumer Advocate, has not decreased as Hawaii clean energy requirements have increased. The Commission should continue to recognize these customer education needs and the utility's obligation to help meet those needs.

d. Hawaiian Electric's Informational Advertising Content and Focus

Hawaiian Electric's informational advertising will focus on providing energy information to its customers, including educating the public about and gaining their support for the investments needed to help achieve the State's RPS law and other clean energy requirements, as well as overall general energy efficiency and conservation information to help build attitudinal change which results in such behavior becoming a way of life for customers. HECO RT-10A at 6-7. Tr. (Vol. V) at 877-878 (Unemori), 941 (Alm).

It will also address information included in Hawaiian Electric's existing corporate communications campaign, such as informing customers about safety (including education about outages caused by mylar balloons), rights to submit damage claims, and customer programs and services such as Hawaiian Electric's *Sun Power for Schools*, Arbor Day "Right Tree, Right Place," and public meetings such as those held for the IRP process. The estimated expenses include television, radio and print advertising and collateral materials to more aggressively inform customers about energy efficiency and conservation measures, including publicizing the Company's *Live Energy Lite* events and programs, and to help build a conservation "ethic" with customers. HECO T-10 at 52; HECO's response to CA-IR-125, CA-RIR-6.

e. The Company's Request for Informational Advertising is Not Moot

Although the Commission's D&O No. 24171 in the HECO's 2005 Rate Case stated that the Company's request for an additional $750,000 advertising to bring total utility O&M informational advertising to $1 million was "moot" because it had approved the RCEA pilot program, the issue is no longer moot because the RCEA pilot program has ended. It is now reasonable to restore utility advertising to levels that will at least partially allow for a base level of mass media marketing to maintain the awareness and momentum established by the advertising efforts over the last several years. HECO's responses to CA-IR-233 at 4 and CA-IR-402 at 2 to 3; HECO RT-10A at 14; HECO T-10 at 53; Tr. (Vol. V) at 944-45 (Alm).

f. The Requested Budget for Informational Advertising is Reasonable and Appropriate

Hawaiian Electric is requesting a total of $1.1 million in non-labor costs for informational advertising expenditures, an amount about one third of the total amount spent by the Company on customer informational advertising in each of the prior two years. HECO RT-10A at 9-11; Tr. (Vol. V) at 874 (Unemori).

(i) Approval of the Proposed Budget Will Complement the PBF Administrator's Advertising Budget

Some of Hawaiian Electric's informational advertising will complement efforts by the Public Benefits Fund Administrator ("PBF Administrator") by recommending actions (e.g., install solar water heaters, buy Energy Star appliances, install CFLs) that direct customers to the PBF Administrator's programs. Other advertising conducted by Hawaiian Electric will identify actions that are not related to the PBF Administrator's programs, e.g., turning off light, watching out for phantom loads, taking shorter showers, etc. as well as educating customers about the importance of reducing energy use during peak times. HECO RT-10A at 6-7, 51-52; Tr. (Vol.

V) at 874-75, 913 (Unemori) and 940 (Alm); HECO's responses to CA-IR-233 at 1, 5, to CA-RIR-11 at 1-2 to CA-IR-233 at 1. With the planned incorporation of more intermittent renewable energy resources onto Hawaiian Electric's grid to meet state policy goals, managing peak time demand and educating the public about peak load concept and the impact of renewable energy resources will be even more critical. HECO RT-10A at 7-8.

Based on discussion with the PBF Administrator, it appears that its funding would be used to (1) establish a new brand, (2) market the energy efficiency programs, and (3) provide any ongoing energy awareness messaging to support long-term consumer attitudinal and behavioral change. HECO RT-10A at 3; Tr. (Vol. V) at 933 (Hee); HECO's response to CA-RIR-9 and Attachment 2. Although HECO is not making a judgment about the adequacy of the advertising budget outlined by the PBF Administrator for the purposes of its administration of the specific energy efficiency programs, based on the amount outlined with the PBF Administrator's Contract for Services with the PUC, the PBF Administrator's advertising efforts with respect to increasing energy awareness are not likely to be anywhere near as extensive as what the Company has conducted in the recent past to increase such awareness amongst its customers. HECO responses to CA-RIR-8 at 1 and CA-IR-416 at 2; HECO RT-10A at 2-3. The PBF Administrator has approached the Company to discuss, on a preliminary basis, the possibility of supplementing the PBF Administrator's advertising efforts with Company advertising in order to achieve two of its three objectives (1) help establish a new overall brand for the energy efficiency programs and (2) to promote customer energy awareness needed for long-term attitudinal and behavioral change. HECO RT-10A at 5; Tr. (Vol. V) at 933 (Hee); HECO's response to CA-RIR-14.

Regardless of who has formal responsibility for administering specific DSM programs, the Company and SAIC agree that getting the public to understand the urgency and what it will take to transition to a cleaner energy future and to act on that urgency is a huge task and a shared responsibility by many. Tr. (Vol. V) at 876-77, 881-82, 912 (Unemori) and 942, 956-57 (Alm); HECO's responses to CA-IR-125 and -402 and CA-RIR-11.

g. The Reduction Proposed by the Consumer Advocate Would Leave the Company with Insufficient Resources to Fulfill its Responsibilities and Accomplish its Objectives

The Consumer Advocate proposed a negative adjustment to remove $774,000 of non-labor informational advertising costs from the test year, resulting in $342,000 for the 2009 test year non-labor expense for informational advertising. CA-T-1 at 111; HECO RT-10A at 2; Tr. (Vol. V) at 875-76 (Unemori). If the test year amount for informational advertising of $1,116,000 is reduced by $774,000 as proposed by the Consumer Advocate, the remaining funding will be insufficient to fulfill the Company's responsibilities and accomplish its objectives. Achieving attitudinal and behavioral change takes a sustained mass media effort to continually reinforce information with the public. The remaining $342,000 for informational advertising will not support any mass market campaign, especially in an environment with climbing advertising rates, a reduced supply of commercial time availability and proliferation of mass market vehicles. HECO's responses to CA-IR-125 at 4, to CA-IR 402 at 2 and to CA-RIR-12; HECO RT-10A at 11; Tr. (Vol. V) at 919 (Unemori).

The Company is very sensitive to the difficult economic conditions in the state and has made a concerted effort to implement cost containment measures. In the case of resources to educate the public, in the test year the Company already reduced by about two-thirds the total amount budgeted for spending on informational advertising compared to prior two years. Tr. (Vol. V) at 14, 880 (Unemori) and 929 (Hee); HECO's response to CA-RIR-13.

h. Informational Advertising is Successful in Achieving Educational Goals

Actual experience with an extensive informational advertising campaign demonstrates the Company's informational advertising efforts have achieved demonstrated results. HECO RT-1 at 50-51; HECO RT-10A page 3-4; Tr. (Vol. V) at 879 (Unemori); HECO's response to CA-RIR-10; to CA-IR 401 and Attachment 1 at 5, 11 to 13, and 16 to 23 (Ward Research Report, September 2008, resubmitted as Rebuttal Exhibit HECO-R-10A01), to CA-IR-233 at 2 and to CA-IR-401, Attachment 1.

It is important to maintain the momentum the Company has achieved in its energy conservation and efficiency advertising. It is a well established marketing principle that a significant lull in advertising will not only quickly result in a loss of awareness achieved by earlier marketing efforts, it will also require the expenditure of even greater amounts in order to regain that same level of awareness later. Achieving sustained behavior change requires sustained communication. HECO RT-1 at 52; HECO RT-10A at 11-12; Tr. (Vol. V) at 879-80 (Unemori).

2. Employee Benefits

a. Merit Employee Wage Increases

In Section II.2(c) of the Interim Decision & Order, the Commission stated that 2009 test year wages for merit employees were expected to exceed 2007 levels by 8.55%. The Commission found that the record "insufficiently address[ed] the accuracy, reasonableness, and fairness of the proposed wage increases for merit employees given current economic conditions." As a result, the Commission directed the Company to restrict its interim wages to either 2007 levels or the most recent actual labor costs filed with the Commission. The parties were invited to provide additional testimony to explore (i) whether current economic conditions affected merit employee wage increases between 2007 and the 2009 test year, and (ii) whether current economic conditions could lead to lower wages than those agreed upon by the parties in the Settlement Letter. ID&O at 11-12; see also HECO response to PUC-IR-158 (restating the 2007-2009 wage increase as 7.14%, which takes into account the Settlement Letter's 2% wage reduction effective May 2009).[10]

The Company promptly complied with the Commission's directive on interim wages. Revised Schedules Exhibit 3 at 11-13; CA-ST-1 at 6. Regarding the need to adjust merit employee wages in response to economic conditions, the Company filed the supplemental testimonies of (i) Robert A. Alm, Executive Vice President of the Conpany; and (ii) Gayle Furuta-Okayama, Director of the Company's Compensation Division. As an initial matter, it was noted that the Company had employed a comprehensive and well-reasoned approach, including extensive data analysis and officer/director review, in determining its initial 2009 merit wage figures, and had already accounted for the current economic environment by offering to lower merit employee wages for 2009 by $532,000 – a 2.0% drop in the initial wage increase[11]. This was accepted as a reasonable and appropriate cost reduction by both the Consumer Advocate and the DOD, and was included in the Settlement Letter. HECO ST-1 at 33-34; Settlement Exhibit at 24-25; HECO ST-15A at 9, 12.

Mr. Alm and Ms. Furuta-Okayama made clear in their respective supplemental testimonies that no further reduction of merit wages is warranted. They raised five main points

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[10] HECO agreed in settlement to reduce the merit salary increase for 2009 by 2%, to an overall merit increase of 2.5%. HECO-S-1103 at 2. Given the current economic environment and in the interest of reaching a global settlement in this proceeding, the Company proposed to lower the O&M labor expenses for merit employees for 2009 by $532,000. The Consumer Advocate and the DOD agreed to the reduction. Settlement Exhibit at 24-25. See also HECO T-13, Attachment 1, Final Settlement and Revised Schedules HECO-WP-1121.

[11] During 2009, the Company actually gave out a total of 0.4% in merit increase in December, to address vertical compression between supervisors and their bargaining unit direct reports.

in support of this view. First, the merit employee wage increases, as reduced by the Settlement Letter, are in line with the 2009 increases of other employers in Hawaii and the United States having the same labor pool and suffering the same economic conditions generally. Recent surveys from (i) the Hawaii Employers Council, regarded as the best local source of compensation data for companies doing business in Hawaii, and (ii) WorldatWork, a renowned source of compensation data both nationally and internationally, provide hard data to this effect. HECO ST-1 at 34; HECO ST-15A at 10-11.

Second, any further wage reduction would compromise the Company's ability to retain its most valuable employees and also make it more difficult to attract qualified candidates. The resulting increase in employee turnover would hamper productivity and require the Company to spend more on recruiting to fill critical vacancies. These potential costs would be exacerbated by the declining number of U.S. power engineering graduates and the industry-wide shortage of skilled utility workers. HECO ST-1 at 34; HECO ST-15A at 13-16.

Third, any attempt to eliminate the proposed increases and hold merit salaries to 2007 levels would cause the Company's long-standing problem of pay compression – merit employees earning less than their unionized peers, or earning less than 10% above their unionized subordinates (which includes being paid *less than* their subordinates' wages) – to be "severely compounded." The Company would have a harder time drawing quality candidates into key merit supervisor roles, and may be forced to rely on less capable, less efficient personnel. The Company would also be more vulnerable to unionization of dissatisfied merit workers, similar to what took place in 1999 with the unprecedented formation of a professional bargaining unit in the System Operation department, consisting of electrical engineers and systems analysts. HECO ST-15A at 3-8. The costs associated with more severe pay compression may far outweigh the additional savings in merit employee wages.

Fourth, it bears mention that the Company's proposed merit wage increase should not be overstated: it is not guaranteed for all merit employees, as opposed to the situation involving non-merit employees and their respective wages. Each merit employee must perform at a satisfactory or better level, and not be at the maximum of his/her market rate, in order to be considered for an increase. This structure helps ensure that merit employees are paid commensurate with their contributions to the Company's success. HECO ST-15A at 2-3.

Finally, in light of current economic conditions, the Company has become even more vigilant in reviewing expenses, establishing spending priorities and identifying opportunities to save money across all business areas. Examples of proactive measures taken by the Company include careful review and reworking of contracts with various vendors in the energy production and administrative areas. HECO ST-1 at 34-35. This across-the-board focus on cost containment has already yielded a Settlement Letter providing for lower, yet still competitive merit wage increases. Cost cutting must not be unreasonably pushed to the point of (i) hurting employee retention rates and the Company's image in the job market, and (ii) sparking merit worker dissatisfaction and possible unionization, among other issues. These various costs appear, in the aggregate, to overwhelm any monetary benefit accrued by slashing agreed-upon merit wage increases for 2009 even more.

However, the Company's position in this proceeding is that HECO is willing to reduce the stipulated revenue requirements for certain larger items [Tr. (Vol. VIII) at 1380 (Williams)], such as the remaining 2% wage increase for merit employees that did not take place on May 1, 2009. If the Commission adopts HECO's position, additional downward adjustments to O&M labor expenses of $580,000 ($532,000 merit + $48,000 merit with overtime) and for the associated payroll taxes of $48,000 ($44,000 merit + $4,000 merit with overtime) will need to be reflected in the stipulated revenue requirements. The Company also intends to correct for the merit with overtime, which was not taken into account in determining the initial 2% merit adjustment in settlement. This correction, as quantified in this Brief, results in an additional merit salary reduction of $48,000 (merit with overtime) and an associated downward adjustment for payroll taxes of $4,000.[12] The Company's position as explained above, will result in a total additional downward adjustment to O&M labor expenses of $628,000 ($580,000 + $48,000) and payroll tax expenses of $52,000 ($48,000 + $4,000), which would reduce the stipulated revenue requirements by approximately $746,000.

Merit Salary Reduction

In direct testimony, the Company explained how the merit salaries were determined for the 2009 test year. To estimate salaries for the test year, salaries as of December 31, 2008, were increased by 4.0% effective May 1, 2009, plus .30% effective September 1, 2009, and .20% effective December 2009. The salary budget for merit positions was based on an assessment of HECO's competitive market, identification of HECO's position within this competitive market, market trends regarding future salary increases and an evaluation of internal "compression" with bargaining unit pay levels. HECO T-13 at 47-48 and HECO T-17 at 21-22.

In the settlement agreement, HECO agreed to reduce the merit salary increase for 2009 by 2%, to an overall merit increase of 2.5%. HECO-S-1103 at 2. In the interest of reaching a

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[12] In calculating the downward adjustment of $532,000 to reflect a 2% reduction in 2009 merit wage levels and the associated reduction in payroll taxes of $44,000 ($532,000 x 8.29% payroll tax rate) in settlement, the Company inadvertently did not take into account the merit with overtime group. The resultant impact of this correction, as quantified in this Brief, is an additional merit salary reduction of $48,000 and an associated downward adjustment for payroll taxes of $4,000 ($48,000 x 8.29% payroll tax rate). The Company discovered this omission in the course of calculating the 2009 test year merit salary adjustment amounts at the 2007 wage levels to comply with the ID&O, which took into account the merit with overtime group.

global settlement in this proceeding and given the current economic environment, the Company proposed to lower the O&M labor expenses for merit employees for 2009 by $532,000. The Consumer Advocate and the DOD agreed to the reduction. See HECO T-13, Attachment 1, Final Settlement for the calculation of the $532,000 adjustment. See also Revised Schedules HECO-WP-1121. A summary of the adjustment amounts by block of account is shown in the table below. Settlement Exhibit at 24-25.

BLOCK OF ACCOUNTS	O&M LABOR EXPENSE REDUCTION ($ THOUSANDS)
PRODUCTION	($128)
TRANSMISSION	($42)
DISTRIBUTION	($80)
CUSTOMER ACCOUNTS	($27)
CUSTOMER SERVICE	($37)
ADMINISTRATIVE AND GENERAL	($218)
TOTAL	($532)

3. Non-Merit Employee Wage Increases

In Section III.(g) of the Interim Decision & Order, the Commission noted the lack of information in the record on the "degree of labor cost flexibility" for non-merit employees. The Commission expressed interest in learning "the extent to which non-merit employee labor costs could be lower than those proposed for the 2009 test year due to current economic conditions." ID&O at 15.

In response, the Company filed the supplemental testimony of Michael H. McInerny, Manager of the Company's Industrial Relations Department, who indicated that the non-merit wage increases set for 2009 are reasonable and appropriate even in the present economic environment. Mr. McInerny first noted that wage increases for non-merit employees are currently dictated by the Collective Bargaining Agreement between the Company and the IBEW (the "CBA"). The CBA, as amended, provides for increases of 3.5%, 4% and 4.5%, effective 11/1/2007, 1/1/2009 and 1/1/2010, respectively. No provisions exist for the Company to either

(i) adjust the wage increases of unionized employees over the term of the CBA, or (ii) renegotiate such increases in light of current economic conditions or for any other reason. HECO ST-15B at 2-3.

Regarding the reasonableness of the CBA's wage structure, Mr. McInerny confirmed that the Company regularly reviews the definitive survey of the Public Utility Employers Institute ("PUEI"), a consortium of 17 public utility companies in the western United States, to better understand compensation trends in the industry. PUEI annually surveys Lineman wages among its membership; it considers the Lineman position a "universal benchmark for purposes of comparing non-merit employees' wage rates" because the Lineman's job duties are standard and very similar across different public utilities and geographic areas. HECO ST-15B at 4; Tr. (Vol. II) at 274-75 (McInerny); see also HECO response to PUC-IR-163 ("The PUEI group only surveys wages for the lineman position among its membership. Other functional area positions are not surveyed by PUEI.") The Company relies on PUEI's survey to find a competitive "middle space" in the range of lineman wage increases, and uses that percentage target for all non-merit wage positions when negotiating with the IBEW. Tr. (Vol. II) at 275-76. 279 (McInerny). Over time, this approach has enabled the Company to place reasonable and effective controls on non-merit wages. In 1995, the Company was ranked second highest in Lineman wages out of 14 companies responding to PUEI's survey; by 2009, the Company's wages had fallen to eleventh out of 14. HECO ST-15B at 5; Tr. (Vol. II) at 275-76. 279 (McInerny). With respect to general wage increases, each of the Company's annual increases from 2001 to 2006 fell below the average for all PUEI survey respondents. HECO Hearing Exhibit 12 at 2.[13] At the panel evidentiary hearing, Steve Carver of the Consumer Advocate

[13] HECO Hearing Exhibit 12 only provides Company wage increase data from 2000 to 2006. No average increase benchmark is given for year 2000.

discussed his own separate analysis of the Company's non-merit wages, and stated that he "did not see any wage rates that appeared to be out of line given the high[] cost of living in Hawaii." Mr. Carver also acknowledged the Company's "fairly constant" job vacancy rate over time, noting that one would expect the vacancy rate to decrease sharply if Company wage increases became unusually attractive to job seekers. Tr. (Vol. II) at 256 (Carver); see also Tr. (Vol. II) at 256 (Brosch) (expressing accord with Mr. Carver's comments).

The IBEW took notice of the steady decline in relative wages, which led them in 2007 to reject the Company's initial proposed wage increase of 3.5% on each of the three effective dates – 11/1/2007, 1/1/2009 and 1/1/2010. Mr. McInerny had recommended this flat percentage, judging it to be fair and competitive with other PUEI companies. Tr. (Vol. II) at 269-70 (McInerny). The final agreed-upon percentages were 3.5%, 4% and 4.5%, with the last figure considered "high" compared to PUEI wage trends. But because the IBEW had taken a very hard line in wage negotiations and had voted to go on strike, Company management decided to make this rational concession to help reach a settlement and to avoid the major service disruptions that a work stoppage may cause. Tr. (Vol. II) at 269-72 (McInerny).

At the panel evidentiary hearing, the Commission asked, in light of the economic downturn and prior concerns about the upcoming 4.5% wage increase, whether it might be reasonable for the Company to start renegotiations with the IBEW over non-merit wages. Company personnel and witnesses for the Consumer Advocate expressed reservations to that idea, for several reasons. First, the union has a historical tendency to take a very tough line on collectively bargained benefits. Mr. McInerny, who negotiated union contracts for 10 years prior to joining the Company, noted that it was a natural part of his old job to be "very hardheaded" towards organizations requesting changes to union contracts; and for a company to gain any sort of traction in contract renegotiations, it must "demonstrate more of a poverty situation," to the point where the livelihood of the business is at stake. If the Company is making any sort of profit, the union will not budge, current economic conditions notwithstanding. This long-standing union mindset, coupled with the emergence of new and even more demanding union leadership, has led the Company to conclude that for all practical purposes, renegotiation of the CBA is a dead end. Tr. (Vol. II) at 272-74 (McInerny); see also Tr. (Vol. II) at 313 (Alm) (commenting on the new union leadership's "pound-on-the-table" approach and their member push for 10-15% wage increases in the next contract – a "wholly unreasonable" target given the current economic climate).

Second, if the Company were to get aggressive and file suit against the union to reduce previously bargained-for wages, it would appear to have little precedent to work with. Mr. Carver of the Consumer Advocate offered that in his experience, "it is extremely difficult to challenge the reasonableness of [] bargaining wage rates that [have] been separately negotiated." Mr. Carver could not recall a single case where such a challenge had been made. Tr. (Vol. II) at 255 (Carver); Tr. (Vol. II) at 256 (Brosch) (agreeing with Mr. Carver's comments); cf. HECO ST-1 at 36-38 (citing to multiple decisions, by the Commission and courts in other jurisdictions, in favor of collectively bargained electricity discounts for employees, negotiated in good faith).

Finally, notwithstanding any success in renegotiating non-merit wages, the Company would be faced with significant political fallout, in terms of both its relationship with the union and its reputation with the public. Mr. Carver noted the potential reluctance of Company management to "expend[] [its] political capital" by initiating renegotiations, however well-intended. He recalled his earlier court experiences involving challenges to Bargaining Unit agreements, and his amazement "at the public press response and the Bargaining Unit members' response, to the quote/unquote Audacity [sic] of the regulators to even consider going after [] arm's length[,] negotiated wage rates." Tr. (Vol. II) at 295-96, 300 (Carver). To willingly endure such hostility from the union and the media, Mr. Carver said he would "need information that shows that the results are wholly out of line based upon the local economy, as well as the competitive marketplace." Tr. (Vol. II) at 296 (Carver). This is not the case here: The Company's non-merit wages are right in step with the wages of similarly situated public utility companies, who are suffering through the same economic conditions and have also felt pressure to make wage and other cost adjustments.

Taken as a whole, the Company's approach to non-merit wage increases has proven to be conservative and well thought out. The Company relies on PUEI's industry-standard pay data in monitoring non-merit wage trends, and has managed over time to remain competitive, yet middle-of-the-pack, with its compensation structure. It has accomplished this within the framework of multiyear, collective bargaining agreements, negotiated thoroughly and in good faith with the union. Although the Company uses best efforts to forecast non-merit wage trends and to propose wage increases to the union accordingly, it cannot ensure that each year's increase will compare favorably with the state of the economy. But to stay on reasonably good terms with the union and to avoid frequent – and often contentious – wage negotiations, the Company has kept the tradition of hashing out longer-term agreements, then waiting a few years to return to the bargaining table. According to Mr. McInerny, who has a wealth of negotiating experience on both the union and Company sides, returning to these agreements and making ad hoc wage adjustments would be wholly rejected by the union and, practically speaking, would amount to a waste of time and effort. Furthermore, the courts seem opposed to findings of unreasonableness in collectively bargained wages, adding another layer of resistance to any attempt at wage reduction. And Company relations with the media and general public, as well as relations with the union, would likely be strained if the Company pushed for reductions. For these reasons, the Company should be allowed to abide by the CBA's wage provisions and continue its long-standing and effective handling of non-merit wages.

4. Medical Costs

In Section III.(j) of the Interim Decision & Order, the Commission noted that there appeared to be significant increases in expenses between the 2007 test year interim award and the 2009 test year in certain business areas, including "admin & general." The Commission flagged this area as possibly being subject to further examination. ID&O at 16.

In response, the Company filed the supplemental testimony of Julie K. Price, the Company's Manager of Compensation and Benefits, concerning, among other things, medical costs. Ms. Price noted that the increase in the Company's medical plan costs from 2007 to 2009 was primarily due to (i) increases in premiums under the HMSA and Kaiser medical plans, and (ii) an increase in the number of covered employees. Medical plan premiums increased as follows:

Medical Plan	% Increase from 2007 to 2009
HMSA PPP	13.3% - 14.8%
HMSA HPH	14.0% - 15.1%
Kaiser	2.7%

HECO ST-13 at 5; see also HECO-S-1302. The number of employees used to determine medical plan costs rose from 1,530 per the 2007 settlement to 1618 for test year 2009. HECO ST-13 at 6.

Despite the above circumstances, the Company has been and continues to be proactive in containing medical costs that are within its control. First, back in January 1989, the Company implemented a cafeteria plan known as "FlexPlan," which was designed to control medical plan costs by allowing employees to purchase benefits with "FlexCredits" based on their individual needs. By paying employees back for unused FlexCredits, the FlexPlan incentivizes employees to waive certain medical plan coverage, resulting in lower premiums and lower utilization of benefits. The Company estimates that about 97 employees will waive medical coverage in test year 2009, yielding an approximate cost savings of $578,000. Tr. (Vol. I) at 193-94 (Price). Also, by requiring employees to pay benefits in excess of their allocated FlexCredits on a pre-tax basis, the FlexPlan reduces FICA taxes payable by the Company as well as by the employees. HECO ST-13 at 6-7; Tr. (Vol. I) at 193 (Price). In addition, since 1999, negotiations between the Company and the International Brotherhood of Electrical Workers (the "IBEW") have led to increased deductibles, co-payments and FlexPlan prices, which have resulted in greater total contributions by employees to defray the Company's medical costs. For example, the Company has increased medical plan participants' required co-payments from $18.00 per doctor visit and $50.00 per hospital admission in 2007 to $20.00 and $100.00, respectively, in 2009. These changes helped offset, in part, the aforementioned increases in plan premiums. HECO ST-13 at 6-7.

As a second means of containing medical costs, the Company maintains its long-standing Health and Wellness Division, which gives employees more power to manage their own health and thereby reduce their need for medical benefits. The division's programs include flu shots; screening programs for cholesterol, blood pressure and diabetes; case management programs for employees to monitor cholesterol, diabetes, asthma and other chronic illnesses; weight-loss and exercise programs; and the dissemination of health-related educational material. HECO ST-13 at 7; Tr. (Vol. I) at 193, 195 (Price).

Third, although the Company rightly provides medical benefits to its temporary employees and retirees, it limits the assistance for these individuals in certain respects. Temporary employees must contribute more for medical benefits than regular employees; moreover, they do not receive all group insurance benefits. Tr. (Vol. I) at 128-29 (Price). Retirees have access to the Company's health and wellness programs, but not to flu shot administrations. Tr. (Vol. I) at 195 (Price).

As a fourth cost-cutting approach, the Company engaged a third-party consultant, Aon Consulting, Inc. ("Aon") to examine the Company's medical plan premiums, explore various funding options, and participate in negotiations with HMSA to lower the Company's medical costs as much as possible.. The most significant product of Aon's efforts was a retrospective premium arrangement with HMSA, effective January 1, 2008, for funding the medical plan for the Company's active employees. Under this arrangement, the Company "continues to pay monthly premiums[,] and any gains or losses at the end of the plan year are carried forward to offset future gains or losses in subsequent years." This results in lower premium rates because "the benefits pooling charge, which pays for $150,000 specific stop loss, is removed and large claims amounts are included in the plan experience." The HMSA rates for 2008 were reduced by approximately 1.1%. HECO ST-13 at 8. In 2009, HMSA provided an initial rate increase of 22.1%, based on 12 months of utilization; but after discussion between Aon and HMSA, this increase was lowered to 16.2% under the retrospective premium arrangement by (i) using 24 months of utilization, instead of 12 months (since the previous 12 months included some atypically large claims); and (ii) increasing HMSA's risk and retention charges. HECO ST-13 at 8; Tr. (Vol. I) at 192-93 (Price).

Finally, although its current labor contract does not expire until October 31, 2010, as of

July 2009 the Company was already formulating a strategy for negotiations, scheduled to begin in Summer 2010. As in the past, "a strategy for addressing high-cost items will be developed, considering the economic conditions and the effect on customers." HECO ST-13 at 9.

Given the Company's wide array of cost-containment techniques and its focus on long-term strategies, it is clear that the net increase in medical costs from 2007 to 2009 was well-managed and is quite reasonable in light of rising provider rates and more employees receiving medical coverage.

5. Employee Count and Labor Expense Adjustment, Including HCEI-Related Positions

In its direct testimony, Hawaiian Electric proposed a 2009 test year average and end of year employee headcount of 1,621. HECO T-15 at 3; HECO-1503. Labor O&M expense totaled $84,581,000, summarized as follows:

Block of Accounts	Direct Testimony O&M Labor	Source
Production	$33,012,000	HECO-701 at 1
Transmission	4,985,000	HECO-809 at 1
Distribution	12,473,000	HECO-809 at 1
Customer Accounts	8,102,000	HECO-901 at 2
Customer Service	3,398,000	HECO-1005 at 1
Administrative & General	22,611,000	HECO-1101 at 5
TOTAL	$84,581,000	

The primary driver of the rate case update was the Energy Agreement which described the actions required to make Hawaii energy independent and still recognized the need to maintain the financial health of the Hawaiian Electric Companies to achieve this objective. Stipulated Exhibit at 22. See also HECO T-1 Rate Case Update at 15-21. The Company proposed to include additional positions, of which 13 were "HCEI-related" as described in the rate case updates. Hawaiian Electric responses to CA-IR-278 and CA-IR-355.

At the same time, Hawaiian Electric recognized that the actual employee count was significantly below the test year staffing count and could not be achieved. In recognition of the difference between actual and test year staffing levels, Hawaiian Electric proposed a one-time downward adjustment of $1,729,000 for labor expense, employee benefits and payroll taxes for the test year and a decrease in employee count of 27 employees as discussed in HECO T-1 Rate Case Update at 22-24 and HECO T-15 Rate Case Update at 15 and calculated in HECO T-15 Rate Case Update Attachment 6. These reductions were based on a 2.37 percent vacancy rate for the Company, excluding the Power Supply process area, which was estimated using the multivariate regression methodology and data that was available at the time. HECO T-15 Rate Case Update Attachment 6 at 1-3.

Stipulated Settlement Agreement

In order to settle the issues in the *Stipulated Settlement Letter* filed May 15, 2009, the Company proposed a 2.68 percent vacancy rate, excluding the Operating Division as well as the Maintenance Division of the Power Supply process area, which was accepted by the Consumer Advocate and the Department of Defense to reach global settlement.[14] The Company's revised vacancy rate is derived from an estimated regression function using additional employee count information for the period from January 2007 through March 2009 submitted in the Hawaiian Electric response to CA-IR-354.

The results of Hawaiian Electric's revised vacancy rate estimate translated to a total labor downward adjustment of $2,521,000 (and a total reduction of 35 positions), $792,000 (and eight positions) more than the Company's initial estimate in its rate case update. Settlement Exhibit

[14] The Company excluded the Operating Division of the PSO&M Department since it must still expend labor expense by incurring overtime to provide round-the-clock coverage or near round-the-clock coverage and operations of the various generating plants (further discussion regarding the duties and responsibilities of the Operating Division is found on HECO T-7 at 52-53), regardless of the vacancy rate it experiences. Settlement Exhibit at 23. The Company also excluded the Maintenance Division of the PSO&M Department since it still committed to performing the work utilizing additional overtime and/or contracted supplemental labor.

HECO T-15 Attachment 1 Final Settlement. A significant amount of the additional reduction to the test year is due to the Company's updated estimate of employee benefit expenses per employee, which increased the estimated employee benefits cost per person from $14,700 to $23,400 per covered employee. Settlement Exhibit at 24; Settlement Exhibit HECO T-15 Attachment 1 Final Settlement at 2. The allocation to the various block of accounts is presented below.

SUMMARY OF ADJUSTMENT ATTRIBUTED TO A
REDUCTION IN HEADCOUNT IN SETTLEMENT AGREEMENT

Block of Accounts	2009 Test Year Rate Case Update	Labor Expense	Payroll Tax	Employee Benefits	Total Settlement Adjustments
Production (w/o Mtnce and Ops RAs) *	$6,799,000	($182,000)	($15,000)	($95,000)	($292,000)
Transmission	5,068,000	(136,000)	(11,000)	(71,000)	(218,000)
Distribution	12,717,000	(341,000)	(28,000)	(178,000)	(547,000)
Customer Accounts	8,102,000	(217,000)	(18,000)	(113,000)	(348,000)
Customer Service	3,470,000	(93,000)	(8,000)	(48,000)	(149,000)
Administrative & General	22,517,000	(603,000)	50,000)	(314,000)	(967,000)
Total Reduction		($1,572,000)	($130,000)	($819,000)	($2,521,000)

* Total Production O&M labor is $33,439,000 (HECO T-7 Rate Case Update Attachment 1) for a total 2009 test year rate case update O&M labor of $85,313,000.
Settlement Exhibit at 24.

Revised Schedules in Response to Interim D&O

In accordance with the July 2, 2009 Interim D&O, the Company filed on July 8, 2009 its *Revised Schedules Resulting from Interim Decision and Order* with explanations for adjustments to the Company's 2009 test year estimates. Among the costs the Company had to address was the expense of HCEI-related positions.

In Section II.1. of the Interim D&O, the Commission stated that by letter dated April 6, 2009, it "advised the Parties that their Statement of Probable Entitlement and Proposed Interim Decision and Order should not include any mechanisms or expenses related to programs or applications that have not been approved by the commission (e.g., decoupling, REIP, and AMI)." IDO at 7. In the Interim D&O, the Commission specifically disallowed costs associated with implementation of the revenue balancing account ("RBA") at this time. The Commission also ordered the exclusion from interim rates the costs of the new positions identified in the rate case update that were created because of the various proposed HCEI initiatives and that have not yet been approved. IDO at 8-9.

To comply with the Interim D&O, Hawaiian Electric removed a total of $1,051,000 from interim rates ($697,000 of O&M labor costs, $303,000 of employee benefits and $51,000 in payroll taxes) associated with 13 positions the Company added in the rate case update. The Company stated that it removed all the costs of these positions even though these positions performed functions related to HCEI programs as well as other work activities outside of these programs and stated that it would address recovery of the costs of these positions later in testimony.[15] Revised Schedules Exhibit 3 at 3-4.

Supplemental Testimony

In Supplemental Testimonies, Exhibits and Workpapers filed July 20, 2009, Hawaiian Electric stated with respect to HCEI-related positions that when it received the April 6, 2009 letter from the Commission, the Company should have adjusted the use of the term "HCEI" to differentiate activities which are not "new" (i.e., HCEI-related) from those which are ongoing Commission initiatives. HECO ST-1 at 29-30. It also described the major organizational changes which were effective March 2, 2009 to support its Clean Energy efforts while continuing to deliver reliable service and quality customer service. HECO ST-15 at 4-6.

[15] In the Interim D&O, the Commission directed the Company to also remove costs for positions related to the Amended Solar Saver Pilot Program ("SSP") if it had not already done so. In its response, the Company confirmed that it removed the costs related to SSP in its rate case update, so further adjustments were not required. IDO at 9; Revised Schedules Exhibit 3 at 5.

In its supplemental testimony, Hawaiian Electric pointed out that the reductions in employee headcount of 35 employees in the *Stipulated Settlement Letter* between the parties in this proceeding lowered the average 2009 test year employee headcount from 1,636 to 1,601, which was six less than the actual June 30, 2009 staffing count of 1,607. HECO ST-15 at 11. The removal of the 13 HCEI-related positions as a result of the Interim D&O further decreases the average test year headcount and diverges from the Company's actual headcount.

While Hawaiian Electric complied with the Interim D&O, it believed that the removal of the expenses are not justified and is seeking to recover these costs in the final decision and order. The Company explained in several supplemental testimonies the various functions of each of the 13 positions[16] it removed to show that these positions also perform non-HCEI-related functions, to demonstrate the need for these positions now and that the Company is being penalized for taking steps now toward achieving an energy self-sufficient future. HECO ST-15 at 12-13.

Consumer Advocate's Comments and Hawaiian Electric's Response

After the Company filed its *Revised Schedules Resulting from Interim Decision and Order*, July 8, 2009, the Consumer Advocate filed its comments on the Company's revised schedules on July 15, 2009, in which it stated on page 1 "...the Consumer Advocate believes that HECO's proposed adjustments were conservatively prepared, views the revised schedules as being in general compliance with the Commission's Interim D&O and does not have any objections to HECO's filing." On page 2, the Consumer Advocate stated "...the intent of the

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[16] Refer to HECO ST-7 (Giovanni) for the Power Supply Engineering Department Project Manager position; HECO ST-10 (Hee) for the Director of Special Projects and Senior Rate Analyst (two positions); HECO ST -11 (Nanbu) for the Lead Corporate Accountant position; HECO ST-15 (Chiogioji) for the Senior Financial Analyst position; HECO ST-15C (Roose) for Renewable Energy Planning Division – Director, Senior Renewable Energy Engineer and Renewable Energy Engineers (2) (four positions in total); and HECO ST-15D (Seu) for Senior Technical Services Engineers (2) and Power Purchase Negotiation Division - Director and Negotiator (four positions in total).

Interim D&O may be subject to interpretation. Some reasonable dispute may exist as to the level and scope of Hawaii Clean Energy Initiative ("HCEI") related costs that should be included in or excluded …."

The Company filed a letter, *Comments on the Consumer Advocate's July 15, 2009 Letter*, on July 17, 2009. The Company stated on page 2 of its July 17, 2009 letter "Section II.1. of the ID&O specified three types of HCEI-related items that would be excluded from interim rate relief: a) sales decoupling, b) HCEI-related positions, c) HCE[I]-related outside services. The remaining items specified in the Consumer Advocate's Attachment 1 are not associated with sales decoupling or HCEI-related positions." On August 3, 2009, the Commission issued its *Order Approving HECO's Revised Schedules*, which stated the following:

> The commission has reviewed the Revised Schedules and subsequent filings by HECO and the Consumer Advocate. Based on that review and on the entire record herein, the commission finds HECO's adjustments in the Revised Schedules to be reasonable and in compliance with the Interim Decision and Order...

Responses to Commission Information Requests

In preparation for the evidentiary hearings and to enable the Commission to potentially narrow the number of issues addressed at hearings, the Commission and its consultant, the National Regulatory Research Institute, submitted information requests to the parties. Commission letter, *Re: Docket No. 2008-0083 – Application of Hawaiian Electric Company, Inc. for Approval of Rate Increases and Revised Rate Schedules and Rules*, filed October 5, 2009. In response to information requests about HCEI-related positions, Hawaiian Electric stated the following:

> When Hawaiian Electric received the Commission's letter dated April 6, 2009 stating not to include any mechanisms or expenses in the Statement of Probable Entitlement related to programs or applications that have not been approved by the Commission, it assumed that it could include positions that worked on other

> HCEI-related initiatives. These initiatives included those whose implementation were not subject to Commission approval of a Company application, such as negotiating renewable power purchase agreements. Work required to plan for and prepare HCEI applications and to support Company involvement in HCEI-related proceedings before the Commission was assumed to be allowed. Hawaiian Electric also assumed that it could still include positions that did a combination of some work covered and some work not covered by the April 6 letter. In hindsight, the Company should have clarified the functions of these positions to show that it was abiding with the April 6 letter.

Hawaiian Electric's response to PUC-IR-118 at 2; see also Tr. (Vol. I) at 21-23 (Alm).[17]

In the response to PUC-IR-118 Attachment 1, the Company provided a table showing the percent workload on HCEI unapproved activities versus all other work for each of the 13 HCEI-related positions. Attachment 1 also provided the date of hire for each of the positions. Of the ten positions that have already been filled, nine were filled prior to the July 2, 2009 Interim D&O. (Eight positions were hired prior to the April 6, 2009 letter from the Commission.) The tenth position was filled on July 6, 2009, which was the next work day after the July 2, 2009 Interim D&O was issued.

Panel Evidentiary Hearings

During the panel evidentiary hearings held October 26 through November 4, 2009, the issue of the 13 HCEI-related positions were further addressed. In its opening statement, Mr. Alm again apologized for any misunderstanding created by the use of the term "HCEI" and expressed the Company's regret for not clarifying what was meant by this term. He went on to explain that

[17] At the panel evidentiary hearing, Mr. Alm explained that the Company's understanding was that the Commission did not want expenses included in the test year revenue requirements for activities that were not yet approved by the Commission, that not all HCEI activities require Commission approval, that legal and regulatory costs are allowed in interim rates (even for HCEI-related dockets) and that research, testing and development costs require long lead times, the costs of which are already expended by the time an application is filed and are not part of the application (unless the Company capitalizes or requests deferral of the cost for later recovery.) Tr. (Vol. I) at 21-22 (Alm). In addition, these positions did work that was not HCEI-related and would largely have been performed even if the Energy Agreement had not been executed. Tr. (Vol. I) at 22 (Alm). Finally, with the respect to the HCEI-related positions, Mr. Alm pointed out that if the Commission does not allow recovery of the labor costs in the rate case, the costs need to be recovered by some other means, such as through a surcharge or capitalization, to which the Consumer Advocate objects a surcharge mechanism. Tr. (Vol. I) at 23 (Alm).

the Company's understanding was that the Commission did not want expenses included in the test year revenue requirements for activities that were not yet approved by the Commission, that not all HCEI activities require Commission approval, that legal and regulatory costs are allowed in interim rates (even for HCEI-related dockets) and that research testing and development costs require long lead times, the costs of which are already expended by the time an application is filed and are not part of the application (unless the Company capitalizes or requests deferral of the cost for later recovery.) Tr. (Vol. I) at 21-22 (Alm). In addition, these positions did work that was not HCEI-related and would largely have been performed even if the Energy Agreement had not been executed. Tr. (Vol. I) at 22 (Alm). Finally, with the respect to the HCEI-related positions, Mr. Alm pointed out that if the Commission does not allow recovery of the labor costs in the rate case, the costs need to be recovered by some other means, such as through a surcharge or capitalization, to which the Consumer Advocate objects a surcharge mechanism. Tr. (Vol. I) at 23 (Alm).

The HCEI-related positions are required and should be recovered in test year revenue requirements. While some of the time of these 13 HCEI-related positions may be spent on activities that have not yet been approved that the Commission in its April 6, 2009 letter and July 2, 2009 Interim D&O deemed to be excluded from interim rates, a portion of the time is spent on activities that do not require Commission approval. Below provides a summary of the discussion on each of the positions, numbered according to the Company response to PUC-IR-118 Attachment 1.

1. Power Supply Energy Division ("PSED") Project Manager. Ninety-five percent of time for this position is spent on non-HCEI projects and 5 percent on HCEI "unapproved" activities. Response to PUC-IR-118 Attachment 1 at 1. Mr. Giovanni stated at the panel evidentiary

hearings thatthe 5 percent work on HCEI projects represent his time devoted to surveying existing Hawaiian Electric facilities for potential solar collector sites for future projects. Further, while it was called for in the Energy Agreement, it is part of the Company's business and does not relate to any unapproved project. Tr. (Vol. I) at 55-56 (Giovanni).

2. Resource Acquisition Department – Senior Technical Services Engineers (PV Host). Currently, no time is spent on HCEI initiatives. This position works full-time on distributed renewable energy initiatives, such as evaluation of battery energy storage technologies and the Department of Hawaiian Homelands strategic partnership, that the Company has been engaged in prior to or separate from the Energy Agreement. This person is currently working 100 percent of the time on these projects until and unless PV Host is approved, in which case his time will be 50 percent spent on PV Host/ HCEI activities and 50 percent on on-going, non-HCEI renewable energy projects. HECO ST-15D at 5-6. See also HECO ST-15 at 29 and the Company response to PUC-IR-118 Attachment 1 at 1. At the hearings, Mr. Seu stated that, if the Commission were not to approve the PV Host program in 2010, this person would continue to work 100 percent of his time on non-PV Host activities. If the PV Host program is approved, the Engineer would have to take on more responsibilities, work would be reshuffled among the staff to accommodate the new PV Host duties as well as continue with non-PV Host duties. This may require deferring some work or using outside services support. Tr. (Vol. I) at 40-41, 44-45 (Seu).

3. Resource Acquisition Department – Senior Technical Services Engineers (DG). This position is involved in the development of additional utility dispatchable distributed generation projects which have been on-going since the 1990s, well before the Energy Agreement was executed. HECO ST-D at 6-8. Examples include military DGs (including

work from the 2006 memorandum of understanding with the Navy to assess DG development at Pearl Harbor and feasibility analyses and preliminary engineering of DG units at Schofield Barracks) and the dispatchable standby generation ("DSG") project at the Airport. HECO ST-15D at 6-8. See also HECO ST-15 at 29-31 and response to PUC-IR-118 Attachment 1 at 1. While the assessment of converting HECO's existing substation DG units to biofuels was described in the HCEI agreement, the Company did not assume that this and general DG evaluation and project development were HCEI activities because it has been an on-going Company activity. Tr. (Vol. I) at 41-42 (Seu). Therefore, no time is currently spent on HCEI "unapproved" work. However, if biofueling of DG units was fully underway, 67 percent of the person's time would be spent on HCEI-related activities, and 33 percent on non-HCEI activities. Response to PUC-IR-118 Attachment 1 at 1. See also HECO ST-15D at 8.[18]

4. Purchase Power Negotiation Division – Director and
5. Purchase Power Negotiation Division – Negotiator. These two positions are involved in the negotiation and administration of purchase power agreements ("PPAs") and amendments, which have been ongoing and pursued irrespective of the Energy Agreement. PPAs that may arise as a direct result of the Energy Agreement include those that may come from the feed-in tariff. If a feed-in tariff is established that comports with the Company's and the Consumer Advocate's proposal, it is estimated that these two new positions would spend about 25 percent of their time supporting PPAs attributed to the feed-in tariff and 75 percent of their time on IPP proposals not directly related to the Energy Agreement. HECO ST-15D at 8-9;

[18] HECO ST-D at 8 states that 1/3 of the engineer's time would be to eventually support DG biofueling efforts. This translates to 33 1/3 percent (rounded to 33 percent) HCEI-related and 66 2/3 percent (rounded to 67 percent) non-HCEI activities. The percentages shown in HECO ST-D are incorrect at 34 and 66 percent, respectively.

Tr. (Vol. I) at 41-42 (Seu).

6. Renewable Energy Planning Division – Director,
7. Renewable Energy Planning Division – Senior Engineer,
8. Renewable Energy Planning Division – Staff Engineer, and
9. Renewable Energy Planning Division – Staff Engineer. This new division with four employees leads many critical functions directly resulting from Hawaiian Electric's commitment to renewable energy resource planning and implementation, a commitment which pre-exists the Energy Agreement. Extensive information on the work done by these four positions were provided in HECO ST-15C at 4-9 and HECO-S-15C01. In the test year, the labor cost for the entire division is 75 percent non-HCEI, 25 percent HCEI unapproved. That is, labor is allocated between the utilities, Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO"), at 50 percent, 25 percent and 25 percent respectively. Of the 50 percent for Hawaiian Electric, half of the time, or 25 percent, of the labor is focused on HCEI activities (the Big Wind project). HECO-S-15C01 at 1. See also Hawaiian Electric's response to PUC-IR-123. All positions are filled and work done is consistent with the percentage allocations shown in the response to PUC-IR-118. Tr. (Vol. I) at 46 (Roose).
10. Director – Special Projects. This position is responsible for developing the overall strategy to guide the Company's demand response ("DR") strategy. While a majority of the position's time will be spent on Energy Agreement-related activities, this position will also guide the development of the Company's overall DR strategy and work on Residential Direct Load Control ("RDLC") and Commercial Industrial Direct Load Control ("CIDLC") program renewal applications, which are not dependent on the Energy Agreement and are

part of an existing program. HECO ST-10 at 6-7. See also HECO ST-15 at 24-25. According to the Company response to PUC-IR-118 Attachment 1 at 4, 60 percent of this position will work on HCEI unapproved activities. Mr. Hee clarified at the panel evidentiary hearings that, while he expects to file an application for approval of a load aggregator, the Company is still developing a request for proposal in preparation for the selection of that aggregator. Hawaiian Electric does not have an application pending before the Commission, and the percent shown is not for implementation of that program. Tr. (Vol. I) at 53 (Hee).

11. Customer Solutions – HCEI Senior Rate Analyst. The Company stated in its supplemental testimony that this position is directly related to the requirements of the Energy Agreement. HECO ST-10 at 5. The percentages shown in the Company response to PUC-IR-118 Attachment 1 at 5 indicate that 40 percent of the person's time is spent pre-Energy Agreement activities, five percent purchase power clause and 55 percent HCEI activities. However, at the panel evidentiary hearings, Mr. Hee pointed out that percentage of work on HCEI activities was based on "normal regulatory preparatory activities done in 2009 done in preparation of the Company applications for Commission approval and hearings with the Commission. Tr. (Vol. I) at 54-55 (Hee).

12. General Accounting Department – Lead Corporate Accountant. This position is doing more than work related to HCEI initiatives. The primary purpose is to do analyses on power purchase agreements based on accounting standards to evaluate whether arrangements contain a lease and whether there are consolidation issues that will be triggered. On a quarterly basis starting in 2010, the Company needs to do an analysis of each contract and determine whether a consolidation is triggered. The Company will continue to have to evaluate power purchase proposals under EITF 01-8 and SFAS 167 (which amends FIN

46R). Also, the move towards international financial reporting standards ("IFRS") will have significant accounting and financial reporting implications on all U.S. public companies, including Hawaiian Electric. It is prudent to begin the process to convert to IFRS in order to be able to comply with the Security and Exchange Commission's requirements when they become effective. Finally, the workload will increase with approval of HCEI programs, such as decoupling, Big Wind or AMI. Tr. (Vol. I) at 51-52 (Nanbu) and HECO ST-11 at 18-19. Given all this work, the position is estimated to work 25 percent of its time on HCEI unapproved work and 75 percent on all other work, including rate case proceedings. Company response to PUC-IR-118 Attachment 1 at 5.

13. Budgets and Financial Analysis Division – Senior Financial Analyst. This position was originally a Senior Financial Analyst, but during the March 2009 restructuring, a new Budgets and Financial Analysis department was created and the position was filled as a Manager, Budgets and Financial Analysis. Work anticipated for this position, of which about 25 percent of the time is spend on HCEI-related initiatives that are pending but not approved, such as feed-in tariffs, Big Wind and decoupling, has been spread among the department. HECO will allocate this position equally between HCEI and non-HCEI activities. Tr. (Vol. I) at 56-57 (Chiogioji). See also HECO ST-15 at 21-22 and the Hawaiian Electric response to PUC-IR-118 Attachment 1 at 6.

The other parties in this proceeding had no issue with these new positions as Hawaiian Electric had previously addressed their concerns with an employee vacancy adjustment in the stipulated settlement agreement. Tr. (Vol. I) at 60 (Brosch).

In summary, these thirteen positions and $1,051,000 are necessary for the transition of Hawaii to a renewable energy future as reflected in State As has been explained, not all Energy

Agreement activities require Commission approval and Company initiatives may have been done even without the Energy Agreement. Much of the work being done for HCEI-related dockets is the preparatory, regulatory work -- not the actual implementation of the projects -- which is allowed for in interim rates. Most of these vacancies were filled prior to the Commission issuing its April 6, 2009 letter and Interim D&O and inclusion of these positions is in line with existing Company employee count. Finally, recovery of these costs in base rates is preferable than through a separate surcharge mechanism.

a. <u>Impact to Postretirement Benefits Other Than Pensions ("OPEB"), Assuming Elimination of the Employee Discount</u>

<u>Impact to Postretirement Benefits Other Than Pensions ("OPEB"), Assuming Elimination of the Employee Discount</u>

If the electric discount is disallowed, the impacts to the net periodic benefit costs ("NPBC") reflected in the OPEB expense and the associated rate base impact should be taken into account in the Results of Operations. However, as expressed in closing arguments, it is the Company's desire to discuss with the other parties how this adjustment should be reflected. Tr. (Vol. VIII) at 1381 (closing argument). If the electric discount is removed, the other postretirement benefits amount would be revised to $6,268,000 (before employee benefits transfer), which includes the estimated NPBC for 2009 of $5,906,000, reduced by $892,000 for the executive life insurance cost, increased by $1,302,000 for the amortization of the SFAS 106 regulatory asset, and reduced by $48,000 for the amortization of the regulatory liability balance as of June 30, 2009 over 5 years for the second half of 2009 (See HECO ST-11 at 13 and HECO-S-1107 at 1).

<u>Direct Testimony</u>

Hawaiian Electric's Direct Testimony estimate for other postretirement benefits is $5,000,000 (before employee benefits transfer) which includes the estimated net periodic benefits cost ("NPBC") for 2009 of $5,224,000 (see HECO-1304 at 1), reduced by $873,000 for the executive life insurance cost and $498,000 for the electric discount provided to retirees to derive $3,853,000, as shown in HECO-1301 at 1, col i, line 5 and HECO-1301 at 2, note 4. The amortization of the SFAS 106 regulatory asset of $1,302,000 and ($155,000) for the regulatory liability amortization are added to derive the other post retirement benefit amount of $5,000,000. HECO T-13 at 15 and HECO T-11 at 74-76.

By way of background, the employee benefits expense in Direct Testimony includes OPEB expense which reflects the estimated NPBC for 2009 as calculated by Watson Wyatt Worldwide of $5,224,000 less the executive life portion that has been disallowed by the Commission of $873,000, less the amortization (based on one fifth of the balance of the regulatory liability at the beginning of the year) of $155,000, and the amortization of the SFAS No. 106 regulatory asset of $1,302,000. It also excludes the electric discount portion of OPEB for the year in the employee benefits expense, as it is already reflected in the reduced revenues for the test year. HECO T-11 at 75 and HECO T-13 at 16. The electric discount amount for retirees of $498,000 that was eliminated in calculating the OPEB expense was estimated by taking the average for the three-month period (December 2007-February 2008) multiplied by twelve months. HECO T-13 at 16. See also HECO-WP-1356, Attachment 2 at 20.

Hawaiian Electric revised the qualified pension plan and other postretirement benefits amounts for 2009 during the course of the proceeding. The table below summarizes the revisions for the other postretirement benefits.

Postretirement Benefits Other Than Pensions ("OPEB")

Administrative and General Expenses - Employee Benefits

($ Thousands) Description	(A) Direct	(B) Rate Case Update	(C) DOD-IR-101 (Sup. 3/20/09, 3/30/09) DOD-IR-104 (Sup. 3/20/09, 3/27/09)	(D) Feb '09 OPEB Adj. Settle Exhibit HECO T-13, Att. 2 HECO-S-1301	(E) Settlement	(F) Adj. as a result of Removal of Schedule E	(G) Estimate Excluding Electricity Discount
Other Postretirement Benefits (NPBC)	5,224	5,224	6,941	1,717	6,941	(1,035)	5,906
Less: Executive Life Program	(873)	(873)	(892)	(19)	(892)	-	(892)
Amortization of SFAS 106 Regulatory Asset	1,302	1,302	1,302	-	1,302	-	1,302
Less: Electricity Discount	(498)	(498)	(498)	-	(498)	498	-
Amortization of Regulatory Liability - 2008	(155)	(155)	(155)	77	(78)	-	
Amortization of Regulatory Liability - 2009	-	-		30	30	-	(48) (b)
Total Other Postretirement Benefits	5,000	5,000	6,698	1,805	6,805	(537)	6,268
O&M Expense Portion (Transfer rate of 28.59%)					4,859	(383)	4,476

Sources: HECO-1301 at 1-2; HECO-1303 at 3; HECO-1304 at 1; HECO T-13 Rate Case Update, Attachment 1 at 2; Exhibit CA-101, Schedule C-14 at 1; DOD-IR-101 Supplement 3/30/09 at 4; DOD-IR-104 Supplement 3/20/09 Attachment 2 at 2, Attachment 3 at 1, and Attachment 4 at 1; Settlement Exhibit HECO T-13 Attachment 2 at 1; HECO-S-1301 at 1; HECO S-13A02 at 1; HECO S-13A03 at 1; and HECO S-13A04 at 1.

Associated Rate Base Impact
NPBC vs. NPBC in rates

($ Thousands) Description	(H) Direct	(I) Rate Case Update	(J) Settlement Exhibit 1 at 69, column (3) HECO Adjusted	(K) Settle. Exhibit 1 at 69, column (5) DCA's Position	(L) Settlement	(M) Estimate Excluding Electricity Discount
Balance, 12/31/07	-	-	-	-	-	-
<u>2008</u>						
NPBC in rates ($6,350) vs. NPBC for 2008 ($5,573)	(777)	(777)	(777)	(777)	(777)	(777)
Balance, 12/31/08 estimate	(777)	(777)	(777)	(777)	(777)	(777)
<u>2009 test year</u>						
NPBC in rates vs. NPBC for 2009 for 6 months	-	-	297	296	296 (a)	(17) (c)
Amortization - 2008	155	155	155	78		
Amortization - 2009	-	-	-	(30)	48 (b)	79 (d)
NPBC in rates vs. NPBC for 2009 for 6 months						(269) (e)
Balance, 12/31/09 estimate	(622)	(622)	(325)	(433)	(433)	(984)
Average Balance	(700)	(700)	(551)	(605)	(605)	(880)

(880)-(605)=-275

(a) NPBC in rates ($6,350) vs. NPBC for 2009 ($6,943) for 6 months
(b) Amortization (1/5 of 6/30/09 balance) for 1/2 year. (((-777+297=-480)/5)*0.5) See HECO-S-1107 at 1..
(c) NPBC in rates ($6,350 in rates before interim) vs. NPBC for 2009 ($6,316 estimated NPBC for 2009) for 6 months
(d) Amortization of regulatory liability balance (1/5 of 6/30/09 balance) for 1/2 year. (((-777-17=-794)/5)*0.5)
(e) NPBC in rates ($6,853 in rates from interim) vs. NPBC for 2009 ($6,316 actual NPBC for 2009) for 6 months

Sources: HECO-1125; DOD-IR-101 Supplement 3/30/09 at 4, footnote (b); Settlement Exhibit 1 at 68-69; Revised Schedules Attachment A at 1; HECO-S-1107 at 1-3.

The components of the revisions for the other postretirement benefits shown in the table are discussed below.

Rate Case Update

No rate case updates were made for OPEB expense which includes executive life insurance costs, the electric discount, amortization of the SFAS 106 regulatory asset, and regulatory liability, nor were any rate case updates made to the unamortized OPEB regulatory liability balance. As stated in Hawaiian Electric's Rate Case Update, the Qualified Pension Plan and Other Postretirement Benefits expense amounts would be updated by Watson Wyatt in February 2009, based on plan asset values as of December 31, 2008 and other assumption changes. HECO T-13 Rate Case Update at 1.

February 2009 OPEB Adjustment

Hawaiian Electric provided more current pension and OPEB information in supplemental responses to DOD-IR-101 (Supplement 3/20/09 and Supplement 3/30/09) and DOD-IR-104 (Supplement 3/20/09 and Supplement 3/27/09) to reflect the changes received from Watson Wyatt in February 2009. The net periodic pension cost ("NPPC") and net periodic benefit cost ("NPBC") for the test year 2009 were updated to $31,488,000 and $6,941,000, respectively. Attachment 2 of the response to DOD-IR-104 (Supplement 3/20/09) provided the updated amounts. Attachment 3 of the response to DOD-IR-104 (Supplement 3/20/09) provided the effect of the updates on pension and postretirement expenses in account 926000. The higher updated pension and postretirement estimates ($31,488,000 in NPPC and $6,941,000 in NPBC) compared to the prior estimates provided in HECO T-13, Exhibits HECO-1302 through HECO-1304 ($14,623,000 in NPPC and $5,224,000 in NPBC) were primarily due to the reduction in the value of plan assets which resulted in an increase in the amortization of the loss, offset by an increase in the discount rate assumption from 6.125% to 6.625% for the pension and to 6.5% for postretirement. In addition, a change in the asset return rate assumption from 8.5% to

8.25% and the lower value of plan assets resulted in a decrease in the expected return component of the NPPC and NPBC. An explanation of the increased pension and postretirement amounts, as provided by Watson Wyatt Worldwide, was included in Attachment 4 of the response to DOD-IR-104 (Supplement 3/20/09).

The effect of the updated expenses on the pension and OPEB tracking mechanisms were provided in the supplemental response to DOD-IR-101 (Supplement 3/20/09 and Supplement 3/30/09). The effect of the updated expenses on the OPEB tracking mechanism is discussed briefly below.

As discussed in DOD-IR-101 (Supplement 3/20/09), the more current OPEB expense for 2009 test year includes the NPBC for 2009 of $6,941,000 (as provided by Watson Wyatt in mid-February 2009 and reflects the asset valuation as of December 31, 2008), plus the amortization of the SFAS 106 regulatory asset of $1,302,000, less the executive life portion of OPEB of $892,000, less the electric discount portion of $498,000 and less the amortization of the OPEB regulatory liability as of December 31, 2008 of $155,000 (one-fifth of the regulatory liability balance at the end of December 2008 of $776,762), for a net OPEB expense of $6,698,000 (before employee benefits expense transfer). The Company recalculated the difference between OPEB in rates of $6,350,000 and the actual OPEB for 2009 (NPBC per Watson Wyatt and the amortization of the SFAS 106 regulatory asset less the executive life portion of OPEB and the electric discount provided to retirees in the test year) of $6,943,000. This difference until the interim decision (prorated on a monthly basis) will be accumulated as a regulatory asset through the estimated interim decision date. After the interim decision, the amount of the actual OPEB and the OPEB in rates was assumed to be the same for 2009. DOD-IR-101 (Supplement 3/20/09) at 2-3. See also DOD-IR-101 (Supplement 3/30/09) and DOD-IR-101 (Supplement 3/30/09) Attachment 1 at 4.

The unamortized OPEB regulatory liability balance and the regulatory asset created as a result of the difference between the actual OPEB and the OPEB in rates through the interim decision would be combined to result in a net regulatory liability amount at the end of 2009 of $325,000 that would be included as a reduction in rate base at the end of December 2009.

Stipulated Settlement Letter

The Settlement Letter revised the 2009 test year estimate for OPEB expense to $6,805,000 (before employee benefit transfer) which reflects the estimated NPBC for 2009, as calculated by Watson Wyatt of $6,941,000, less the executive life insurance cost that has been disallowed by the Commission of $892,000, less the amortization of the net regulatory liability balance as of June 30, 2009 of $48,000, less the electric discount provided to retirees of $498,000, and plus $1,302,000 for the amortization of the SFAS 106 regulatory asset. See Settlement Exhibit HECO T-13 Attachment 2 at 1, lines 5a-8b.

Further, for purposes of settlement, the Parties agreed with the Consumer Advocate's position to include both the regulatory liability resulting from the last rate case in Docket No. 2006-0386 and the new regulatory asset created as a result of the difference between the NPBC in rates vs. actual NPBC for the first half of 2009, and amortize the estimated balance of the regulatory asset/liability amounts as of mid-2009 (the estimated date of the interim decision in this proceeding) over five years. The estimated amortization of $48,000 for the 2009 test year, reflects six months of the annual amortization of the NPBC in rates vs. NPBC for 2008 (-$777,000 ÷ 5 years x 6/12=-$78,000) and also six months of the annual amortization of the NPBC in rates vs. NPBC for 2009 ($296,000 ÷ 5 years x 6/12=$30,000). See Settlement Exhibit HECO T-13 Attachment 2 at 1, lines 8a-8b and Settlement Exhibit 1 at 68-69.

HECO ST-11 and HECO-S-1107 provided further support for the amortization amounts. HECO ST-11 at 13 stated, "The OPEB tracking mechanism was approved on an interim basis in October 2007 in the HECO 2007 test year rate case, in the same interim decision approving an interim rate increase. The OPEB costs included in determining HECO's revenue requirements in the 2007 test year rate case was $6,350,000 as reflected on page 1 of the June 2007 Update for HECO T-12 filed on June 15, 2007 in Docket No. 2006-0386. Because the actual OPEB costs in 2007 was the same as the test year estimate, there was no regulatory asset/liability related to the difference between the OPEB costs in rates and the actual OPEB costs as of the end of 2007. In 2008, the actual OPEB costs were $5,573,000 compared to the $6,350,000 included in HECO's current rates. As shown on HECO-S-1107, the difference of $777,000 is the regulatory liability as of the end of 2008. The estimated OPEB costs for 2009 is $6,943,000. Based on the assumption that interim rates would be established in July 2009, the difference between the OPEB costs in rates of $6,350,000 and the actual OPEB costs for 2009 of $6,943,000 for six months amounted to $297,000 (($6,943,000-$6,350,000)/2). The balance as of June 30, 2009, amortized over five years for the second half of 2009 amounts to $48,000."

The Settlement Letter also discussed the associated rate base impact. The Consumer Advocate proposed an average rate base adjustment of $95,000 (CA-101, Schedule B-2, line 6). In conjunction with the Parties' agreement with the Consumer Advocate's position to amortize the estimated balance of the regulatory liability as of mid-2009 over five years, for purposes of settlement, the Parties agreed to decrease the average net regulatory liability by $95,000. As a result, the agreed to Regulatory Liability – NPBC vs. NPBC in rates was an average balance of $605,000. See Settlement Exhibit 1 at 68-69.

Revised Schedules in Response to Interim D&O

No adjustments were made as a result of Interim D&O for the OPEB expense, which includes executive life insurance cost, the electric discount, amortization of the SFAS 106 regulatory asset, and regulatory liability, nor were any adjustments made to the unamortized OPEB regulatory liability balance.

Hawaiian Electric's Position

As stated above, if the electric discount is disallowed, the impacts to NPBC reflected in the OPEB expense and the associated rate base impact should be taken into account. Currently, the electric discount provided to retirees for the test year is deleted from the OPEB expense estimate, since it is already reflected in the test year in the form of lower revenues. HECO T-11 at 75 and HECO T-13 at 16. If the electric discount is disallowed, an adjustment would need to be made to the NPBC estimate and an adjustment to reverse the electric discount of ($498,000) from the OPEB expense calculation, as illustrated in the table above. Hawaiian Electric would like the opportunity to discuss with the other parties whether this adjustment should be reflected in final rates or simply captured in the OPEB tracking mechanism for future rate recognition.

If the electric discount is removed, the other postretirement benefits expense amount would be revised to $6,268,000 (before employee benefit transfer), which includes the estimated NPBC for 2009 of $5,906,000, reduced by $892,000 for the executive life insurance cost, increased by $1,302,000 for the amortization of the SFAS 106 regulatory asset, and reduced by $48,000 for the amortization of the regulatory liability balance as of June 30, 2009 over 5 years for the second half of 2009. If the Commission removes the electric discount and further determines that the impact to O&M expense and rate base should be incorporated into final rates, the O&M expenses for A&G-Employee Benefits would be reduced by $383,000 (net of employee benefits transfer), which would reduce revenue requirements by approximately $420,000. In addition, the Regulatory Liability-NPBC vs. NPBC in Rates average balance would **increase** by approximately $275,000 ($551,000 x 50%), resulting in a Regulatory Liability-NPBC vs. NPBC in rates average balance of $880,000 ($605,000 +$275,000), **which reduces rate base** and would reduce revenue requirements by approximately $42,000.

6. <u>A&G Outside Services Expense Increases</u>

Outside services expenses recorded in Account Nos. 923010 and 923020 are a part of the broader category of A&G expenses, with respect to which the Commission noted that "there appears to be significant increases in certain expenses between the 2007 test year interim award to the 2009 test year . . . ." IDO at 16. As discussed in supplemental testimony, the Hawaiian Electric's 2009 test year outside services expense is $2.666 million, an increase of $1.346 million over the 2007 test year interim level of $1.320 million. See HECO-S-1103 at 1; HECO ST-11 at 2. The increase in costs from 2007 was primarily due to consultant fees related to Ellipse Upgrade implementation and consultant fees related to the eMESA software implementation. HECO ST-11 at 34-37; see HECO-S-1103 at 6. The Ellipse Upgrade is discussed elsewhere in this Opening Brief.

7. HCEI Outside Services Expenses

Section II.1(c) of the ID&O states as follows with respect to HCEI outside services expenses:

> The Parties described $2,220,000 of Big Wind implementation studies on page 21 of the Settlement Agreement. In settlement discussions, the Parties agreed that HECO recover these costs through the REIP Surcharge. The Parties propose that if HECO does not recover these costs through the REIP Surcharge, it should be allowed to recover them through rates approved in this rate case. These studies, however, relate to an HCEI project not yet approved by the commission. In addition, the commission has not rendered a decision in the REIP docket, Docket No. 2007-0416. As such, the commission does not at this time approve these costs for recovery through interim rates or a surcharge mechanism.

ID&O at 9.

However, Hawaiian Electric had not sought to include the cost of Big Wind Implementation Studies in interim rates. Those costs, as well as other HCEI-related R&D costs were removed from the test year pursuant to the agreement of the Parties in the Settlement:

> In summary, the total amount for HCEI-Related R&D costs that were removed from the test year is:
> - Big Wind Studies – CEIS recovery
> $2,220,000
> - Oahu Electric System Analysis – CEIS recovery
>   677,000
> - AMI R&D – ½ of consulting costs
>   244,000
>
> Total Reduction

$3,141,000

Settlement Exhibit at 22. The removal of these costs was reiterated in the Company's letter to the Commission dated July 17, 2009 in response to the Consumer Advocate's July 15, 2009 comments on the Company's Revised Schedules ("July 17, 2009 Letter"). The July 17, 2009 Letter explained why no other HCEI-related outside services costs were removed in the Revised Schedules after the Settlement and Statement of Probable Entitlement:

> From the wording in this provision of the ID&O, it was clear to the Company that "these costs" referred to the $2,220,000 of Big Wind implementation studies costs. As the Company explained in its July 8 Response, it had already removed $2,220,000 of Big Wind implementation studies costs (and $200,000 of PV Host Program outside consulting costs) from the revenue requirement in its Statement of Probable Entitlement. Since the ID&O did not identify any other HCEI-related outside services costs to be removed from the 2009 test year, the Company made no further adjustments in this area.

Hawaiian Electric's July 17, 2009 Letter at 2.

Notwithstanding the removal of the HCEI-related outside services expenses identified above, certain other HCEI-related outside services expenses remained in the test year. The ID&O at footnote 16 addressed those HCEI outside services expenses that may be recovered in interim rates:

On page 21 of the Settlement Agreement, the Parties agreed to normalize outside services' costs related to participation in commission-initiated proceedings or obtaining commission approval (e.g., legal and regulatory support services) for initiatives identified in the Energy Agreement.

The result is a reduction of $396,000 in test-year outside services costs for the following HCEI-related dockets:

$ 80,000 PV Host Program HECO only, amortized over two years
$ 40,000 PV Host Program MECO & HELCO costs removed
$ 253,000 AMI legal & regulatory amortized over two years
$ 23,000 FIT legal & regulatory MECO & HELCO costs removed

$396,000 Total reduction

The commission will allow HECO, for interim purposes, to include legal and regulatory costs related to the PV Host, AMI, and the FIT programs, as described above.

ID&O at 9-10 n. 16. These expenses were also recognized in Attachment 1, column (H) of the Consumer Advocate's July 15, 2009 comments on the Company's Revised Schedules. Therefore, it is Hawaiian Electric's position that these costs, totaling $333,000 ($ 80,000 PV Host Program HECO only, amortized over two years + $ 253,000 AMI legal & regulatory amortized over two years), should remain in the test year expenses approved by the Final Decision and Order.

8. Cost Variances on CIP Projects Other than CT-1

In Section III.(c) of the Interim Decision & Order, the Commission noted that the Company projected substantial cost variances for the CT-1 project. The Commission expressed concern about the lack of explanatory information in the record regarding cost variances for CT-1 and other CIP projects. ID&O at 14.

With respect to capital improvement projects outside of CT-1, the Company filed two supplemental testimonies, in the areas of Power Supply Engineering (HECO ST-17C) and Energy Delivery (HECO ST-17D) that addressed the process that Hawaiian Electric undertakes in managing the cost of its capital improvement projects.

9. DSM Costs

In the Interim D&O, the Commission stated that "[t]here appears to be a significant increase in IRP/DSM costs in the 2009 test year over previous years. The commission is concerned about the reasonableness of such increases given the transition of energy efficiency

DSM programs to a third-party administrator."[19] IDO at 15.

The 2009 test year base DSM expenses in the Company's direct testimony totaled $2,374,000. This amount was reduced to $2,029,000 after the rate case update and settlement discussion with the Consumer Advocate. The settlement amount of $2,029,000 is approximately $337,000 higher than the average of the previous three years' recorded amounts from 2006 to 2008, and is $363,000 higher than 2008's recorded figure. HECO ST-10; see HECO-S-1003.

Hawaiian Electric's estimate of the 2009 test year Customer Service expenses of $5,784,000 in its settlement position (Settlement Exhibit at 46) does not include incremental expenses for energy efficiency DSM programs, as those expenses were removed from the test year estimate or were already excluded from the test year estimate because they were being recovered through the DSM surcharge as incremental costs. Also, as shown on HECO-S-1000, labor and non-labor expenses for eight energy efficiency programs were removed from the 2009 test year. See HECO ST-10 at 10-11.

The increase in the test year base DSM expenses from prior years is due primarily to increases in expense for the two load management programs that remain with Hawaiian Electric following the transfer of the energy efficiency programs to the PBF Administrator (i.e., the Commercial & Industrial Direct Load Control ("CIDLC") and Residential Direct Load Control ("RDLC") programs). Generally speaking, these increases are related to (1) the effort related to marketing the CIDLC program to customers with smaller potential load reduction potential, (2) the implementation of the full-scale rollout of the Small Business Direct Load Control program element as part of the CIDLC Program, (3) the cost to conduct a comprehensive CIDLC program

[19] Hawaiian Electric provided a detailed explanation of the costs of the IRP activities conducted by the Company in 2008 and 2009, as well as those anticipated through 2010, in its responses to PUC-IRs-165 and -166. In addition, in response to PUC-IR-189, the Company provided information regarding the total cost of IRP/CESP activities in the revenue requirement for both the Settlement Agreement and in rates complying with the Interim D&O.

evaluation, (4) the challenges that a more saturated market is expected to pose for increasing participation in the RDLC program, (5) the cost to conduct a comprehensive RDLC program evaluation, (6) anincrease in advertising expense for the RDLC program,[20] (7) the reallocation of labor hours and vacancies for portions of 2008, and (8) an increase in DSM-related administration labor expense. HECO ST-10 at 10-11; see HECO ST-10 at 11-18.

10. A&G Maintenance Expense Normalization

In the Interim D&O, the Commission stated that although normalization through historical averaging of A&G maintenance costs is appropriate, "the average should not include the test year estimates, because it is inappropriate to create an estimate using a combination of actuals and another estimate." The Commission thus concluded that if $145,000 of capital costs from the Company's Ward Baseyard project were accrued in 2008, the same amount should be removed from the 2008 cost prior to averaging and instead added to the rate base. See IDO at 17-18.

Hawaiian Electric respectfully disagrees with the Commission's position on this issue. Although the Company's A&G Plant Maintenance 2009 test year amount is an estimate, it is based on specific forecasted non-recurring maintenance projects that the Company anticipated doing in the test year. Since the Company identified specific projects to be performed in the test year, it is appropriate to include the costs of these projects in the test year estimates. Due to the significant costs of these projects in the test year, the Company believed it was appropriate to

[20] The 2009 test year Hawaiian Electric advertising expense for the RDLC program is $424,000, an increase of $126,000 over 2008. The increase reflects the anticipation that as the water heating portion of the program approaches market saturation more closely, efforts to market the program will become more expensive. See HECO ST-10 at 16. However, actual 2009 year-to-date program performance has demonstrated that a lower RDLC Program test year advertising expense estimate is appropriate. As a result, Hawaiian Electric no longer maintains that a RDLC Program advertising budget of $424,000 will be necessary to continue to reach the participation goals for the program in 2009. Instead, Hawaiian Electric supports a test year expense estimate for advertising in the RDLC Program of $120,000. See response to PUC-IR-164.

normalize the project costs to a reasonable estimate based on a three-year normalization period which included identified specific projects to be performed in year 2010. See HECO ST-14 at 3-4.

Since these are non-recurring general maintenance expenses, using a test year estimate where the test year estimate is higher than previous recorded actuals without normalization would generally result in over-recovery from ratepayers in years beyond the test year. This over-recovery would not be reset until the next rate case. The opposite is also true when the test year estimate is lower than the previous recorded actuals. Without normalization, this situation would generally result in under-recovery by the utility. This under-recovery would also not be reset until the next rate case. See HECO ST-14 at 4.

The $145,000 of capital costs from the Ward Baseyard project were removed from the 2009 test year general plant maintenance expenses and should have been included in the 2009 capital plant additions used in calculating the Company's ending 2009 rate base and 2009 test year average rate base. However, the $145,000 was inadvertently excluded from the 2009 capital plant additions. The Ward Baseyeard project costs were not accrued in 2008, as the project commenced in 2009. See HECO ST-14 at 4.

IV. RATE BASE

A. INTRODUCTION

In direct testimony, the Company estimated the test year average rate base at proposed rates using the base case scenario at $1,332,636,000. HECO-1801(c); HECO-WP-2306 at 3). In the Company's Rate Case Update, this estimate was updated to $1,334,958,000. HECO T-23 Rate Case Update, Attachment 7 at 3; HECO T-18 Rate Case Update at 9; Settlement Exhibit at 66. During settlement discussions, the Parties agreed on the average rate base at proposed rates of $1,252,882,000. Settlement Exhibit at 67. See also Statement of Probable Entitlement,

Exhibit 1 at 1.

It is Hawaiian Electric's position that the Final Decision and Order should approve a test year average rate base at current effective rates in the amount of $1,251,571 at proposed rates in the amount of $1,250,907. See Hawaiian Electric's Motion for Second Interim Increase for CT-1 Revenue Requirements, filed November 19, 2009, Exhibit 1 at 4.

HECO generally calculates the test year rate base in accordance with the concepts adopted by the Commission in prior rate case decisions, including the stipulation of the Parties in the Stipulated Settlement Letter filed September 5, 2007 ("HECO 2007 Stipulation") and Interim Decision and Order No. 23749 (dated October 22, 2007) in Docket No. 2006-0386 ("HECO 2007 Interim Decision"), HECO's test year 2007 rate case; the stipulation of the Parties ("HECO 2005 Stipulation") and Decision and Order No. 24171 (dated May 1, 2008) in Docket No. 04-0113 ("HECO 2005 Decision"), HECO's test year 2005 rate case; Decision and Order No. 14412 (dated December 11, 1995) in Docket No. 7766 ("HECO 1995 Decision"), HECO's test year 1995 rate case; and Decision and Order No. 13704 (dated December 28, 1994) as amended by Order No. 13718 (dated January 5, 1995) in Docket No. 7700, HECO's test year 1994 rate case. HECO T-18 at 3.

The rate base is calculated as the sum of the average balances for the following investments in assets:

net cost of plant in service,

property held for future use,

fuel inventory,

materials and supplies inventories,

unamortized net Statement of Financial Accounting Standards ("SFAS") 109 regulatory asset, unamortized system development costs,

unamortized reverse osmosis ("RO") water pipeline regulatory asset,

asset retirement obligation ("ARO") regulatory asset, and

working cash,

HECO T-18 at 4, less the sum of the average balances for the following funds from non-investors:

unamortized contributions in aid of construction ("CIAC"),

customer advances for construction,

customer deposits,

accumulated deferred income taxes ("ADIT"),

unamortized investment tax credits,

unamortized gain on sales,

pension regulatory liability, and

postretirement benefits other than pensions ("OPEB") regulatory liability.

HECO T-18 at 38-39.

The following table summarizes Hawaiian Electric's 2009 test year average rate base at direct testimony, Rate Case Update, settlement, Revised Schedules and final position reflecting the relief requested in Hawaiian Electric's Motion for Second Interim Increase:($000's)

	HECO T-18 Direct Testimony	HECO T-18 Rate Case Update	Settlement	Revised Schedule	Final Position
Source:	HECO-1801(C)	Rate Case Update HECO T-23 Att. 7 at 3	Statement of Probable Entitlement	Revised Schedule Exhibit 1 at 3	Motion for Second Interim Exhibit 1 at 4
INVESTMENT IN ASSETS SERVING CUSTOMERS					
Net Plant in Service	1,469,005	1,474,183	1,470,532	1,386,762	1,470,532

Prop. Held for Future Use	2,331	2,331	2,331	2,331	2,331
Fuel Inventory	82,683	82,683	45,005	43,274	43,274
Mat'l. & Supply Inventories	16,015	16,105	16,203	16,182	16,182
Unamort. Net SFAS 109 Reg. Asset	61,310	60,524	60,236	60,236	60,236
Unamort. Sys Dev Costs	17,452	17,644	6,310	6,310	6,310
RO Water Pipeline Reg. Asset	3,183	3,183	3,183	3,183	3,183
ARO Regulatory Asset	13	13	11	11	11
FUNDS FROM NON-INVESTORS					
Unamortized CIAC	-178,410	-181,756	-181,066	-181,066	-181,066
Customer Advances	-848	-848	-877	-877	-877
Customer Deposits	-7,695	-8,244	-8,391	-8,391	-8,391
ADIT	-135,277	-132,671	-144,531	-142,272	-144,531
Unamortized ITC	-32,831	-33,838	-29,376	-29,376	-29,376
Unamortized Gain on Sales	-1,055	-1,055	-1,046	-1,046	-1,046
Pension Reg. Asset (Liability)	-2,746	-2,746	202	202	202
OPEB Reg. Asset (Liability)	-700	-700	-605	-605	-605
WORKING CASH					
Working Cash at Current Effective Rates	40,971	41,055	15,480	15,115	15,202
Change in Rate Base - Working Cash	-766	-815	-719	-550	-664
Average Rate Base at Proposed Rates	1,332,636	1,334,958	1,252,882	1,169,423	1,250,907

Settlement Exhibit at 65.

In direct testimony, HECO T-18, the Company estimated the test year average rate base at proposed rates using the base case scenario at $1,332,636,000. HECO-1801(c) and HECO-WP-2306, page 3. Subsequently, this estimate was updated to $1,334,958,000 to reflect updates to rate base components primarily driven by the requirements and commitments specified in the Energy Agreement. HECO T-23 Rate Case Update Attachment 7 at 3; HECO T-18 Rate Case Update at 9. This average rate base estimate reflects the base case scenario with the inclusion of the HCEI Implementation Studies and excludes the Company's updated sales forecast reduction. Settlement Exhibit at 66.

In its direct testimony, the Consumer Advocate recommended a test year average rate base at proposed rates of $1,259,321,000. CA-101 Schedule B. The Consumer Advocate accepted the Company's test year average rate base estimate except for seven items:

1) reflection of December 2008 actuals (see Rate Base Update – 2008 Actuals section below);

2) revision to the regulatory asset (liability) of the pension tracking mechanism (see the Regulatory Assets section below);

3) the reversal of CIS test year impacts (see the CIS O&M Expense and Rate Base Impacts section above);

4) adjustment to fuel inventory (see the Fuel Inventory section below);

5) adjustment to the working cash estimate (see the Working Cash section below);

6) adjustment to update the 2009 ADIT ending balance (see the ADIT section below); and

7) adjustment to the ADIT reserves (see the ADIT section below).

Settlement Exhibit at 66.

As shown on DOD-106, the DOD proposed the following two adjustments to rate base:

1) reflection of December 2008 actuals (see Rate Base Update – 2008 Actuals section below); and

2) reversal of CIS test year impacts (see the CIS O&M Expense and Rate Base Impacts section above).

Settlement Exhibit at 66.

The DOD also had concerns with the calculation of working cash (see the Working Cash section below) and the need to update the 2009 year-end ADIT balance to recognize 2009 bonus tax depreciation (see the ADIT section below). Settlement Exhibit at 66-67.

Based on the discussion summarized below, the Parties reached agreement on each of these differences. As a result of these settlements, the Parties agreed in the Settlement on the average rate base at proposed rates of $1,252,882,000. Statement of Probable Entitlement, Exhibit 1 at 1; Settlement Exhibit at 67.

Rate Base Update - 2008 Actuals. The Company considered updating the 2008 year-end balances to reflect year-end actuals, and to update 2009 changes to the balances, once the year-end actuals became available. However, the Company was asked by the Consumer Advocate, and the Company agreed, to update these amounts prior to the end of 2008 to provide the Parties with more opportunity to review the updates. Response to DOD-IR-94, Supplement 3/9/09. Thus, Hawaiian Electric's rate base estimate reflected the 2008 year-end estimates proposed in the Rate Case Update. The Consumer Advocate proposed a decrease of $16,370,000 and the DOD proposed a decrease of $16,551,000 to reflect actual December 2008 amounts. CA-101, Schedule B-1; DOD-107. The Consumer Advocate disagreed with the Company's interpretation of the request for an early update and conveyed its intention to reflect actual 2008 year-end balances consistent with prior HECO rate cases. The Company did not agree with using the 2008 year-end actuals as the beginning balance in calculating the average rate base without an opportunity to also update its 2009 end of year balance. However, for purposes of settlement, the Company agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1 except for the fuel inventory adjustment. CA-101, Schedule B-1, line 3. The Company reran its production simulation and reflected that estimated fuel inventory adjustment. Refer to the Fuel Inventory section below for further discussion. Settlement Exhibit at 67.

Regulatory Assets (Liability) – NPPC vs. NPPC in Rates and Regulatory Assets (Liability) – NPBC vs. NPBC in Rates. The Company provided more current pension and OPEB information in supplemental responses to DOD-IR-101 (3/20/09 and 3/30/09) and DOD-IR-104 (3/20/09 and 4/3/09). The Consumer Advocate recalculated the regulatory Assets (Liability) - NPPC vs. NPPC in Rates and Regulatory Assets (Liability) – NPBC vs. NPBC in Rates proposed by Hawaiian Electric based on the tracking mechanisms for Pension and OPEB and utilizing the updated NPPC and NPBC for 2009. However, there were differences in the amortization amounts proposed by HECO and the Consumer Advocate due to the assumption on the commencement of amortization in 2009. Settlement Exhibit at 67.

Regulatory Assets (Liability) – NPPC vs. NPPC in Rates. Hawaiian Electric's average regulatory liability for the test year was $2,746,000. HECO-1124. Based on updated pension expense estimates for 2009 received from the Company's actuary, Watson Wyatt Worldwide, which reflected the pension plan asset values as of December 31, 2008, the Company provided a calculation of the Regulatory Asset – NPPC vs. NPPC in rates assuming the NPPC in rates would be reset in mid-2009, and assuming a full year amortization of the regulatory liability balance as of the end of 2008. Settlement Exhibit at 68.

The Consumer Advocate's proposed average rate base adjustment is $2,948,000. CA-101, Schedule B-2, line 3. The Consumer Advocate's position included both the regulatory liability resulting from the last rate case and the new regulatory asset created as a result of the difference between the NPPC in rates vs. the actual NPPC for the first half of 2009, and amortizing the estimated balance of the regulatory asset/liability amounts as of mid-2009 (the estimated date of an interim decision in this proceeding) over five years. The Consumer Advocate's estimate amortized in 2009 six months of the annual amortization of the 2008 NPPC in rates vs. NPPC regulatory liability ($(3,051,000) ÷ 5 years x 6/12) and six months of the annual amortization of the 2009 NPPC in rates vs. NPPC ($6,889,000 ÷ 5 years x 6/12). CA-101, Schedule C-14, line 4 and footnote c. Settlement Exhibit at 68.

To settle the issue of this proceeding, the Parties agreed with the Consumer Advocate's position to amortize the estimated balance of the net regulatory asset as of mid-2009 beginning mid-2009 (i.e, reflecting 6 months of annual amortization) over five years and to increase the average net regulatory asset by $2,948,000. This results in an agreed Regulatory Asset – NPPC vs. NPPC in Rates average balance of $202,000. Settlement Exhibit at 68.

Regulatory Assets (Liability) – NPBC vs. NPBC in Rates. HECO's average regulatory liability for the test year as shown in HECO-1125 is $(700,000). Based on updated OPEB estimates for 2009 received from the Company's actuary, Watson Wyatt Worldwide, which reflected the OPEB plan asset values as of December 31, 2008, the Company provided a calculation of the Regulatory Liability – NPBC vs. NPBC in rates assuming the NPBC in rates would be reset in mid-2009, and assuming a full year amortization of the regulatory liability balance as of the end of 2008. Settlement Exhibit 68-69.

The Consumer Advocate's proposed average rate base adjustment is \$95,000. CA-101, Schedule B-2, line 6. The Consumer Advocate's position included both the regulatory liability resulting from the last rate case and the new regulatory asset created as a result of the difference between the NPBC in rates vs. the actual NPBC for the first half of 2009, and amortizing the estimated balance of the regulatory asset/liability amounts as of mid-2009 (the estimated date of an interim decision in this proceeding) over five years. The Consumer Advocate's estimate amortized in 2009 six months of the annual amortization of the 2008 NPBC in rates vs. NPBC (\$(777,000) ÷ 5 years x 6/12) and also 6 months of the annual amortization of the 2009 NPBC in rates vs. NPBC (\$296,000 ÷ 5 years x 6/12). CA-101, Schedule C-14, line 4 and footnote c. Settlement Exhibit at 69.

For purposes of settlement, the Parties agreed with the Consumer Advocate's position to amortize the estimated balance of the regulatory liability as of mid-2009 over five years (i.e., reflecting 6 months of the annual amortization of the 2008 NPBC in rates vs. NPBC and also 6 months of the annual amortization of the 2009 NPBC in rates vs. NPBC) and decrease the average net regulatory liability by \$95,000. This results in an agreed to Regulatory Liability – NPBC vs. NPBC in Rates average balance of \$605,000. Settlement Exhibit at 69.

As described in the Impact to Postretirement Benefits Other Than Pensions ("OPEB") section, if the electric discount is disallowed, the impacts to NPBC reflected in the OPEB expense and the associted rate base impact should be taken into account in its Results of Operations. If the Commission removes the electric discount and further determines that the impact to O&M expense and rate base should be incorported into final rates, the Regulatory Liability-NPBC vs NPBC in Rates average balance rate base would be reduced by approximately \$275,000 (\$551,000 x 50%), resulting in a Regulatory Liability-NPBC vs NPBC in Rates average balance of $880,000 ($605,000 + $275,000)

1. Additions To Rate Base

a. Introduction

In this case, these are the following uses of funds from investors that are added to the rate base: (1) Net Cost of Plant in Service, (2) Property Held for Future Use, (3) Fuel Inventory, (4) Materials and Supplies Inventory, (5) Unamortized Net SFAS 109 Regulatory Asset, (6) Unamortized System Development Costs, (7) Unamortized RO Water Pipeline Regulatory Asset, (8) ARO Regulatory Asset, and (9) Working Cash.

b. Net Cost Of Plant In Service

In direct testimony, Hawaiian Electric's test year estimate for average Net Cost of Plant in Service was $1,469,005. HECO-1801(c); Settlement Exhibit 1 at 66. In the Company's Rate Case Update this estimate was revised to $1,474,183. HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65.

For purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This results in an agreed to average Net Cost of Plant in Service for the 2009 test year of $1,470,532,000. Settlement Exhibit at 70. See also Settlement Exhibit at 66-67.

In the Company's Revised Schedules in response to the ID&O, the test year estimate for average Net Cost of Plant in Service was $1,386,762. Revised Schedules Exhibit 1 at 3; Revised Schedules Attachment A at 2.

As set forth in the Motion for Second Interim Increase, the Company's final position on the amount that should be included in the Final Decision and Order for the average Net Cost of Plant in Service is $1,470,532. Motion for Second Interim Exhibit 1 at 4.

c. **Property Held for Future Use**

As reflected in the table above, Hawaiian Electric's average 2009 test year balance for property held for future use in direct testimony, Rate Case Update and settlement is $2,331,000. Settlement Exhibit at 65-66.

As set forth in the Motion for Second Interim Increase, the Company's final position on the amount that should be included in the Final Decision and Order for the test year balance for property held for future use is $2,331,000.. Motion for Second Interim Exhibit 1 at 4.

d. **Fuel Inventory**

The test year average fuel inventory balance presented in direct testimony was $82,683,000. HECO-505. See also HECO T-5 at 33. In Hawaiian Electric's Rate Case Update filed on December 22, 2008, the average fuel inventory balance remained at $82,683,000. HECO T-23 Rate Case Update Attachment 7 at 3.

The Consumer Advocate and the DOD each proposed reductions to take into account December year-end actuals and the Consumer Advocate also proposed using lower December 2008 fuel prices. CA-101, Schedule B, Schedule B-2 and CA-101, Schedule B-4; DOD-103.

For purposes of settlement, the Parties agreed to accept the Company's April 2009 Update production simulation results, including Hawaiian Electric's December 2008 fuel prices, and the Company's updated average fuel inventory balance of $45,005,000 for the 2009 test year. See HECO T-5 April 2009 Update, Attachment 1, at 8 for calculations.

In the Revised Schedules, Hawaiian Electric revised the test year average fuel inventory. The Company derived the settlement average fuel inventory balance by computing the average of the beginning of 2009 test year fuel inventory (without the CIP CT-1) of $43,274,000 and the end of 2009 test year fuel inventory (with CIP CT-1) of $46,737,000. Settlement HECO T-5

Attachment 1 at 8. Because CIP CT-1 will use biodiesel for fuel and was scheduled to go into service on July 31, 2009, the beginning of test year fuel inventory did not include any biodiesel but the end of test year fuel inventory did. Removal of CIP CT-1 from the test year in the Revised Schedules necessitated the removal of biodiesel from the end of test year fuel inventory. To be conservative, the Company used the beginning of test year balance of $43,274,000 (which does not include biodiesel) for the end of test year fuel inventory, resulting in an average annual total inventory of the same amount ($43,274,000) for the 2009 test year. The adjustment resulting from the ID&O is a reduction of $3,463,000 to the end of year total inventory. Revised Schedules HECO T-5 Attachment 1. The adjusted average annual total inventory amount of $43,274,000 is conservative since the end of test year fuel inventory reflected in the settlement agreement includes 780,727 barrels of fuel, or 16,785 more than the beginning of test year balance of 763,942 barrels. Settlement HECO T-5 Attachment 1 at 8. By using the inventory value of $43,274,000 for the end of test year balance for the purposes of this adjustment, the Company effectively used the lower amount of 763,942 barrels for both the beginning and end of test year balances.

In the Motion for Second Interim Increase, the Company maintained its test year estimate for the test year average fuel inventory in the amount of $43,274,000. The Company did not request that any biofuel inventory for CIP CT-1 be included in the 2009 test year fuel inventory. Motion for Second Interim Increase, Statement of Facts at 7 and Exhibit 1 at 4.

e. **Materials and Supplies Inventories**

In direct testimony, Hawaiian Electric's 2009 test year average balance for materials and supplies inventory was $16,015,000. HECO-WP-2306; Settlement Exhibit 1 at 65. In the Company's Rate Case Update, the 2009 test year average balance for materials and supplies inventory remained $16,015,000. HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65..

For purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals identified in CA-101, Schedule B-1. This resulted in an agreed value for average materials and supplies inventories for the 2009 test year of $16,203,000. Settlement Exhibit at 65. A breakdown of the allocation between Production and T&D was determined by applying the 2008 year-end actuals from Attachment 2 of HECO's response to CA-IR-455 to the materials & supply inventory calculation, resulting in a 2009 average $8,205,000 adjusted Production inventory and $7,998,000 adjusted T&D inventory. Settlement Exhibit at 70. See also see Settlement HECO T-18, Attachment 1.

In the Company's Revised Schedules, Hawaiian Electric made a further reduction to the T&D average materials and supplies inventory for the test year. A new T&D materials inventory forecast for the 2009 test year average inventory and year-ending inventory values was prepared using the 2008 actual year-end inventory value of $8,385,796 as a baseline. Based on the same methodology used in HECO T-8 direct testimony to calculate the T&D materials inventory balance at the end of 2009, the 2008 actual year-end balance was multiplied using the Cost Trends of Electric Utility Construction: Pacific Region for 2009 provided in the confidential Global Insight Power Planner which was provided in Revised Schedules HECO T-8 Attachment 2. The cost trend for both Transmission Plant and Distribution Plant was projected to decrease by 2.6 percent from 2008 to 2009. To calculate the projected 2009 year-end T&D materials inventory value, the Company applied the negative 2.6 percent factor to the 2008 recorded year-end balance. The T&D materials inventory is revised to $8,167,765, based on a 2.6% decrease applied to the 2008 year-end inventory of $8,385,796, which is $43,000 less than that initially forecasted by the Company, prior to the Accounts Payable adjustment. Revised Schedules HECO T-8 Attachment 3. The revised 2009 average inventory value was derived by averaging the actual year's starting value and the projected year-ending value (after the Accounts Payable adjustment), resulting in a 2009 test year T&D materials inventory average value of $7,976,281. Revised Schedules Exhibit 3 at 16-17.

Therefore, it is Hawaiian Electric's position that the test year average balance for materials and supplies inventory approved in the Final Decision and Order should be $16,182,000. Revised Schedules Exhibit 1 at 3; Motion for Second Interim Increase Exhibit 1 at 4.

f. Unamortized Net SFAS 109 Regulatory Asset

The test year estimate of SFAS 109 Regulatory Asset ("Reg Asset") average balance presented in direct testimony was $61,310,000. HECO-1606 at 2; Settlement Exhibit at 65. See also HECO T-16 at 18. In the Rate Case Update, the CWIP Equity Ongoing was updated due to the revised 2008 and 2009 estimates of AFUDC shown in HECO T-16 Rate Case Update Attachments 5 and 6. See also Rate Case Update HECO T-16 at 2. This resulted in a revised average balance of $60,524,000. Settlement Exhibit at 65 and 71.

Both the Consumer Advocate and the DOD proposed adjustments to the SFAS 109 Reg Asset average balance. The Consumer Advocate adjusted the SFAS 109 Reg Asset average balance in two steps by a reduction of $144,000 (288,000 x 38.91%) to update for the actual 12/31/08 balance and an identical adjustment to average rate base to update for the same SFAS 109 Reg Asset adjustment carried forward to the 12/31/09 balance. CA-101, Schedule B-1; CA-101, Schedule B-6. For settlement purposes the Parties agreed with the Consumer Advocate's average balance of $60,236,000. Settlement Exhibit at 65 and 71.

It is Hawaiian Electric's position that the SFAS 109 Reg Asset average balance approved in the Final Decision and Order should be $60,236,000. Motion for Second Interim Increase Exhibit 1 at 4.

g. Unamortized System Development Costs

The test year estimate of unamortized system development average balance presented in direct testimony was $17,452,000. HECO-1117; Settlement Exhibit at 65. See also T-11 at 54-59. In the Rate Case Update, the end of the test year balance was updated to reflect an updated deferred project costs for the HR suite project and the resulting updated amortization expense for the year for the project. The unamortized system development average balance in the Rate Case Update was $17,644,000. T-11 Rate Case Update at 8; HECO T-11, Attachment 8; Settlement Exhibit at 65..

The Consumer Advocate adjusted the Unamortized System development costs by $58,000 to update actual 2008 balance and removed the CIS amount of $11,392,000. CA-101, Schedule B-1; CA-101, Schedule B-3. The Parties agreed with the actual 2008 balance as the beginning balance and the CIS removal. For settlement purposes, the Company agreed to forego an update to the 2009 balance to account for the 2008 actual balance. The difference of $1,000 is due to rounding. This results in an agreed Unamortized System Development Cost average balance of $6,310,000. Settlement Exhibit at 65 and 72.

It is Hawaiian Electric's position that the test year amount for Unamortized System Development Cost average balance approved in the Final Decision and Order should be $6,310,000. Motion for Second Interim Increase Exhibit 1 at 4.

h. Unamortized RO Water Pipeline Regulatory Asset

The test year estimate of the RO water pipeline regulatory asset is $3,183,000. HECO T-

18 at 15-16; HECO-1801; Settlement Exhibit at 65. The RO water pipeline regulatory asset accounts for the portion of the RO water pipeline that will be dedicated to the Board of Water Supply of the City and County of Honolulu ("BWS") upon completion of construction. The BWS will then own, operate and maintain that section of pipeline. HECO T-18 at 16.

The test year estimate of the RO water pipeline regulatory asset was unchanged in the Company's Rate Case Update and in the settlement. Settlement Exhibit at 65.

It is Hawaiian Electric's position that the test year amount for the RO water pipeline regulatory asset approved in the Final Decision and Order should be $3,183,000. Motion for Second Interim Increase Exhibit 1 at 4.

i. <u>ARO Regulatory Asset</u>

The ARO Regulatory Asset for the 2009 test year presented in direct testimony was $13,000. HECO-1801; Settlement Exhibit at 65. As discussed above, for purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This resulted in an agreed average ARO Regulatory Asset for the 2009 test year of $11,000. Settlement Exhibit at 72.

It is Hawaiian Electric's position that the average ARO Regulatory Asset for the 2009 test year approved in the Final Decision and Order should be $11,000. Motion for Second Interim Increase Exhibit 1 at 4.

j. <u>Working Cash</u>

In direct testimony, the test year estimate of working cash at current effective rates was $40,971,000. Settlement Exhibit at 65; HECO-1801(c). In the Company's Rate Case Update, the test year estimate of working cash was revised to $41,055,000. Settlement Exhibit at 65; HECO T-23 Rate Case Update Attachment 7 at 3.

After the filing of direct testimonies, the Parties were in agreement on all items included in the working cash calculation and the revenue and payment lag days except as described below. After extensive discussions, also described below, for purposes of global settlement in this rate case, the Parties reached agreement on all items in working cash.

Working Cash for O&M Non-Labor. The Company's position is pension expense, pension regulatory asset/liability amortization, OPEB regulatory asset/liability amortization, system development cost amortization, regulatory commission expense and Waiau Water Well amortization should be included in the working cash calculation and in the calculation of the 30-day expense lag applied to the O&M non-labor components of the working cash study. The Consumer Advocate and DOD objected to the inclusion of these items. More specifically, the Consumer Advocate disagreed with HECO's assertion that these non-cash transactions should be included in cash working capital. Each item will be discussed separately below.

Pension Expense – The Company's position is (1) the revenues associated with the pension expense are subject to the same revenue collection lag as any other revenue item regardless of whether a contribution to the pension plan is made or not, and (2) the Company proposed to include the pension expense in the working cash calculation and in the calculation O&M non-labor expense payment lag with a payment lag of zero days HECO T-18 at 28-29; HECO-WP-1806. The Consumer Advocate disagreed with HECO's assertion that non-cash transactions, in this case pension accruals (or NPPC), are properly includable in the calculation of cash working capital. CA-T-3 at 97-101.

During the settlement discussions, the Company also presented supplemental information regarding the cessation of previously planned pension contributions in the discussion of working cash. The Company made two pension contribution payments in the month of February and

March totaling $2,739,000. A pension contribution schedule totaling $8,218,000 was provided in response to DOD-IR-101 (Supplement 3/20/09) identifying monthly contribution payments from February through September that the Company had planned to make to the pension trust in 2009. DOD-IR-101 Supplement 3/20/09 at 2 and Attachment 1 at 2. In April 2009, additional guidance on funding relief for defined benefit pension plans was received from the IRS including: (1) IRS Notice 2009-22 related to the application of new asset valuation rules included in the "Worker, Retiree, and Employer Recovery Act of 2008" and (2) publication of a Special March Edition of "employee plans news" related to yield curve selection for the target liability calculation. HECO T-18, Attachments 2 and 3.

As a result of adopting the revised assumptions, Hawaiian Electric had the ability to cease contributions beginning in April 2009. The Company's position on payment lag days decreased to negative 109 days based on the amount and timing of the two contributions made. The Consumer Advocate objected to the inclusion of pension expense in the working cash calculation at a payment lag of zero days and to the inclusion of the two 2009 pension contributions in the working cash calculation at a negative 109 days as aberrational and not representative of recurring contribution activity. Settlement Exhibit at 78.

The DOD proposed a 45.6 day payment lag to the pension contribution in calculating a 33-day O&M non-labor payment lag in DOD-109. The DOD objected to the inclusion of pension expense accrued beyond payment in the working cash calculation and in the calculation of the payment lag applied to the O&M non-labor components of the working cash study. Settlement Exhibit at 79.

For purposes of settlement, the Parties agreed to include the contributed portion of the pension expense in the working cash calculation with a payment lag of 14 days which reflects pension funding on a monthly basis at the end of each month. HECO T-18, Attachment 4 at 2. The Parties also agree to exclude the uncontributed portion of the pension expense from the working cash calculation. HECO T-18, Attachment 4 at 1; Settlement Exhibit at 79.

Pension & OPEB regulatory asset/liability amortization – The Company's position is all revenues should be included with a revenue collection lag. The revenues associated with the pension and OPEB regulatory asset/liability amortization are subject to the same revenue collection lag as any other revenue item and a payment lag of zero days. HECO T-18 at 28-29; HECO WP-1806. The Consumer Advocate and DOD disagreed with HECO's assertion that all revenues, including non-cash transactions, are properly includable in the calculation of cash working capital. The Consumer Advocate and DOD's position was that the pension regulatory asset/liability amortization and the OPEB regulatory asset/liability amortization should be removed from the working cash calculation on the basis that they are non-cash transactions. CA-T-3 at 99-101; DOD T-1 at 17-18. For purposes of settlement in this proceeding, the Parties agree to exclude the pension and OPEB regulatory asset/liability amortization from the working cash calculation. Settlement Exhibit at 79.

Amortization Expenses – The Company's position in settlement discussions was that amortization expenses (system development cost amortization, regulatory commission expense and Waiau Water Well amortization) were paid for in advance of the expense recognition and have zero or negative payment lags or should be included as rate base items. Response to DOD-IR-81 and CA-IR-432. The Consumer Advocate disagreed with HECO's assertion that all revenues, including non-cash transactions, are properly includable in the calculation of cash working capital or that these items necessarily merit rate base treatment. However, the Consumer Advocate observed that system development costs are afforded rate base treatment.

The Consumer Advocate and DOD proposed these amortization expenses should be removed from the working cash calculation on the basis that these are non-cash transactions. CA-T-3 at 99-101; DOD T-1 at 17-18. For purposes of settlement, the Parties agreed to exclude the amortization expenses from the working cash calculation. Settlement Exhibit at 79-80.

The revised O&M non-labor payment lag days, as a result of incorporating the above discussed items, is 33 days. Settlement HECO T-18, Attachment 4 at 1. Other differences in the working cash result from differences in the related expense items and will be adjusted according to the settlement proposals for those items. Settlement Exhibit at 80.

Revenue Tax Payment Lag. In direct testimony and Rate Case Update, the Company proposed a 37 day revenue collection lag and a 66 day payment lag for revenue taxes. HECO-1806; HECO T-18 Rate Case Update at 19. In its direct testimony, the Consumer Advocate proposed a 13.5 day revenue collection lag and a 66.1 day payment lag for revenue taxes. CA-101 Schedule B-5; CA-T-3 at 102-04. In DOD T-1 at 19, the DOD noted that whereas the Public Service Company Tax and Public Utility Fees are computed on billed revenues, the Franchise Tax is computed on a cash basis. Consequently, it appears that the expense payment lag for the Franchise Tax used by Hawaiian Electric warrants an adjustment. During the settlement discussions, the Consumer Advocate also proposed an alternative approach which adjusted the payment lag days rather than the revenue collection lag days, resulting in a composite revenue tax payment lag days of 89 days. As detailed in HECO T-18, Attachment 5, for purposes of settlement, the Parties agreed to reflect the revenue tax revenue collection lag at 37 days, the revenue tax payment lag at 66 days, and include a $7,500,000 downward adjustment to working cash to reflect the approximate impact resulting from the differences in the revenue tax payment lag days between the Parties' positions. Settlement Exhibit at 80.

For purposes of fully resolving cash working capital in the present rate case and streamlining and simplifying the presentation and review of this issue in the next rate case, Hawaiian Electric and the Consumer Advocate agreed to the following additional provisions: (a) Hawaiian Electric agreed to update the various revenue and expense lag calculations using a reasonably current study period; (b) the updated workpapers and supporting documents, including underlying transaction detail, will be made available for review by the Consumer Advocate; (c) the Company agreed to work collaboratively with the Consumer Advocate to better quantify and design the expense categories set forth in the updated lead lag study; and (d) Hawaiian Electric agreed to employ calculated revenue and expense lag days that are not rounded to whole days. Settlement Exhibit at 80.

The revised working cash at current effective rate, as a result of incorporating the above discussed items, is $15,480,000. Settlement Exhibit at 65 and 80. See also Statement of Probable Entitlement, Exhibit 1 at 3.

In the Revised Schedules, the estimate of working cash at current effective rates was revised to $15,115,000. Revised Schedules Exhibit 1 at 3; Revised Schedules Attachment A at 2.

It is Hawaiian Electric's final position that the working cash estimate at current effective rates approved in the Final Decision and Order should be $15,202,000. (The change in working cash from the Revised Schedules resulted from revisions in the related expense items that were made between the submission of the Revised Schedules and Motion for Second Interim Incease.) Motion for Second Interim Increase Exhibit 1 at 4.

2. Deductions From Rate Base

a. Introduction

In this case, the following are the sources of funds from non-investors that are deducted from rate base: (1) Unamortized Contributions In Aid Of Construction ("CAIC"), (2) Customer Advances for Construction, (3) Customer Deposits, (4) Accumulated Deferred Income Taxes ("ADIT"), (5) Unamortized Investment Tax Credits, (6) Unamortized Gain on Sales, (7) Pension Regulatory Liability, and (8) OPEB Regulatory Liability. HECO T-18 at 38.

b. Unamortized Contributions In Aid Of Construction

The estimated average unamortized CIAC for test year 2009 presented in direct testimony was $178,410,000. HECO T-18 at 39; HECO-1805; Settlement Exhibit at 65. In the Company's Rate Case Update, the estimate was revised to $181,756,000; HECO T-23 Rate Case Update Attachment 7 at 3.

As described above, for purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This results in an agreed to average Unamortized CIAC for the 2009 test year of $181,066,000. Settlement Exhibit at 65 and 72.

It is Hawaiian Electric's position that the average Unamortized CIAC for the 2009 test year approved in the Final Decision and Order should be $181,066,000. Motion for Second Interim Increase Exhibit 1 at 4.

c. Customer Advances

The estimated average customer advances balance for construction for test year 2009 presented in direct testimony and in the Company's Rate Case Update was $848,000. HECO T-18 at 40; HECO-1801; HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at

65.

As described above, for purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This results in an agreed to average Customer Advances for the 2009 test year of $877,000. Settlement Exhibit at 65 and 72.

It is Hawaiian Electric's position that the average Customer Advances for the 2009 test year approved in the Final Decision and Order should be $877,000. Motion for Second Interim Increase Exhibit 1 at 4.

d. **Customer Deposits**

The estimated average customer deposits balance for test year 2009 presented in direct testimony was $7,695,000. HECO T-18 at 41; HECO-1801. In the Company's Rate Case Update, the estimate was revised to $8,244,000. HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65.

As described above, for purposes of settlement, Hawaiian Electric agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This results in an agreed to average Customer Deposits for the 2009 test year of $8,391,000.

It is Hawaiian Electric's position that the average Customer Deposits for the 2009 test year approved in the Final Decision and Order should be $8,391,000. Motion for Second Interim Increase Exhibit 1 at 4.

e. **Accumulated Deferred Income Taxes**

In direct testimony, the base case estimated average accumulated deferred income tax balance was 135,277,000. Settlement Exhibit at 73 and 75. In the Company's Rate Case

Update, the estimated average accumulated deferred income tax balance was revised to $132,671,000. HECO T-23 Rate Case Update Attachment 7 at 3; HECO-T-16 Rate Case Update Attachment 4 at 1; Settlement Exhibit at 65 and 73.

The Consumer Advocate adjusted the ADIT average balance to update for the actual 2008 year-end balance. The adjustment to actual was $269,000, and its impact on ADIT average balance was accomplished in two steps: first by an adjustment of $135,000 ($269,000 x 50%) to the ADIT average balance to account for the impact of the adjusted 2008 year-end balance and second by a similar adjustment of $134,000 ($269,000 x 50%) to account for the impact of the adjusted 2009 year-end balance. CA-101, Schedule B-1; CA-101, Schedule B-6. Settlement Exhibit at 73.

The DOD adjusted ADIT for the 2008 year-end actual balance by $269,000 and adjusted the average balance by $135,000. DOD-106. As indicated above, the $269,000 adjustment is an adjustment to both the beginning and ending test year balances and therefore the impact to average rate base should be $269,000. Settlement Exhibit at 73.

In direct testimony, the Consumer Advocate further adjusted the ADIT average balance reducing rate base by $1,184,000 related to the 2009 pension and OPEB net regulatory assets/liabilities in the amounts of $3,454,000 and $(433,000), respectively. CA-101, Schedule B-7. This increase in the ADIT offset to rate base was based on the updated expense estimates for 2009 received from the Company's actuary, Watson Wyatt Worldwide and the agreement to account for six months of the pension/OPEB tracker resulting from the updated expense. The OPEB ADIT balance was subsequently revised by the Consumer Advocate based on additional information provided by Hawaiian Electric that caused a restatement of the $1,184,000 rate base reduction to a $2,497,000 reduction. Settlement Exhibit at 73-74. Please see above Regulatory

Assets (Liability)-NPPC vs. NPPC in Rates and Regulatory Assets (Liability) - NPBC vs. NPBC in Rates for further discussion.

The DOD did not include an adjustment for this pension/OPEB tracker. Settlement Exhibit at 74.

Hawaiian Electric compared its latest update to the Consumer Advocate's summary of ADIT rate base adjustments, and in addition to the items discussed immediately above, the Company, the Consumer Advocate and the DOD tentatively agreed on the following two ADIT items (1-2 and 7), but Hawaiian Electric proposed the next four items (3-6) for which neither the Consumer Advocate nor the DOD accounted. CA-101, Schedule B at 2; DOD-106 at 1. In addition, the Company proposed and the Consumer Advocate accepted the last adjustment below (7), which was inadvertently missed by Hawaiian Electric, the Consumer Advocate and the DOD. Settlement Exhibit at 74. The following explains each ADIT item of adjustment:

(1) State ITC. See below for a detailed discussion of the state ITC adjustment. State ITC is deferred and amortized for book and regulatory purposes and ADIT is adjusted for the tax effect of any adjustment to state ITC. As discussed below, the amount of state ITC earned in 2009 is reduced by $8,600,000 and the related adjustment to ADIT is $3,346,000 ($8,600,000 x 38.91%), which increases ADIT and decreases average rate base by $1,673,000. Settlement Exhibit at 74.

(2) Bonus Tax Depreciation. Both the Consumer Advocate and the DOD raised the issue of whether tax bonus depreciation was reflected in HECO's estimated ADIT balances. CA-T-1, page 122; DOD T-1, page 21. Hawaiian Electric did not include any bonus depreciation for 2009 plant additions in the calculation of ADIT in direct testimony or the Rate Case Update. Subsequent to those submissions, bonus depreciation for 2009 was signed into law on February

17, 2009. Settlement Exhibit at 74.

Accordingly, the Company computed a 2009 estimate of tax bonus depreciation and its incremental impact on the ADIT balances for rate base purposes and provided the Consumer Advocate and DOD with the information in Settlement HECO T-16 Attachments 1, 1A, 1B, 1C and 1D. Both the Consumer Advocate and DOD tentatively agreed with the depreciation estimate of $41,132,662 as reasonable. The increase in the test year end balance of ADIT associated with this tax depreciation is $14,396,431, and the impact on average rate base is $7,198,000, or 50% of the total increase. Only the federal 35% rate is used in the calculation of ADIT because Hawaii has not adopted the federal bonus depreciation rules in prior years and is not expected to adopt the 2009 provision. Settlement Exhibit at 74.

(3) CIS. The adjustment to remove the CIS project costs from rate base are shown on the Consumer Advocate exhibit CA-101, Schedule B-3, including the adjustment to ADIT of $306,000 (increase ADIT balance/decrease rate base). However, it appears the Consumer Advocate did not transfer the ADIT adjustment to the Summary of Rate Base Adjustments. Please see section "CIS O&M Expense and Rate Base Impact" above for further discussion.

Based on the Company's proposal to exclude the CIS cost from rate base, the DOD reduced the ADIT average balance by $1,850,000 for the ADIT associated with the CIS tax deduction (see DOD-106), which was revised in the Company's response to CA-IR-396 Attachment 4 at 1. The adjustment attempted to remove the effects of CIS on rate base. Hawaiian Electric and the Consumer Advocate have agreed that the ADIT related to the CIS costs should remain in the ADIT balance for rate base purposes, resulting in the adjustment on average rate base of $306,000, proposed above. Settlement Exhibit at 75.

(4) Emission Fee. The change in the estimated emission fee for 2009 affects ADIT

because for tax purposes, Hawaiian Electric deducts the amount actually paid in the test year, not the amount accrued for book purposes. Accordingly, the increase in the book expense creates a negative deferred income tax. This impact was not accounted for by the Consumer Advocate. The Company calculated its ADIT on the emission fee in its Rate Case Update based on a book expense of $872,000, which the Consumer Advocate proposed. In Rate Case Update T-7, Attachment 2, the Company proposed to increase the emission fee expense to $1,092,000, to which the Consumer Advocate has agreed but has not accounted for the related 2009 ADIT impact of $86,000 (($1,092,000-$872,000) x 38.91%). Average rate base is increased by the $43,000 (50% x $86,000). Settlement Exhibit at 75.

(5) Book Depreciation. Book depreciation was adjusted for various items addressed in CA-101, Schedule C-22. The net reduction in book depreciation of $1,098,000 must be carried through to the ADIT calculation. The impact is an increase of ADIT of $427,000 ($1,098,000 x 38.91%), which correspondingly decreases rate base by the same amount and decreases average rate base by $214,000 (50% x $427,000). Settlement Exhibit at 75.

(6) OPEB Expense. In addition to the Consumer Advocate's adjustment related to the pension/OPEB tracker, another ADIT adjustment related to the OPEB expense was proposed. OPEB expense included in cost of service is a temporary book/tax difference since the actual contributions are deducted for tax purposes. The 2009 ADIT should decrease by $501,000 (($6,941,000-5,652,839) x 38.91%) as a result of the increase in OPEB expense from $5,652,839 in the Rate Case Update to $6,941,000 based on the February 2009 Watson Wyatt estimate. The 2009 average rate base should increase by $251,000 ($501,000 x 50%). Settlement Exhibit at 75.

(7) OPEB Deduction. As discussed in item (6) above, the OPEB cost generates a

temporary difference for which negative ADIT is provided on the book expense. Conversely, positive ADIT is provided on the contributions made that are tax deductible.

In the process of reviewing ADIT, Hawaiian Electric ascertained that ADIT had not been provided for the estimated 2009 contribution for OPEB in the Rate Case Update ADIT balances.

HECO proposes an addition to 2009 ADIT of $2,626,751 ($6,750,839 x 38.91%) for the estimated 2009 OPEB contribution payment of $6,750,839, as provided by Watson Wyatt Worldwide in February 2009. Accordingly, average 2009 rate base decreases by $1,313,000 ($2,626,751 x 50%). Settlement Exhibit at 65 and 76.

For settlement purposes, the Parties agree with the ADIT average balance of $144,531,000. Settlement Exhibit at 65 and 76.

In the Company's Revised Schedules in response to the ID&O, the test year estimate for average ADIT was $142,272,000. Revised Schedules Exhibit 1 at 3.

It is Hawaiian Electric's position that the Final Decision and Order should approve an ADIT average balance of $144,531,000, as adjusted for the ADIT impact due to the 2009 state ITC adjustment. Motion for Second Interim Increase Exhibit 1 at 4. With the proposed adjustment to the Unamortized State ITC as described below and an attendant decrease in ADIT, the Company proposes a decrease of the average ADIT balance of $142,500 (50% of $285,000), resulting in an average ADIT balance of $144,388,500 ($144,531,000-$142,500).

f. Unamortized State ITC

In direct testimony, the base case estimated average unamortized investment tax credit balance was $32,831,000. Settlement Exhibit at 75-76. The Company's average Unamortized State ITC for the Rate Case Update was $33,838,000. HECO-T-16 Attachment 3 at 1; HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65.

The Consumer Advocate adjusted the Unamortized State ITC average balance to update for the actual 2008 year-end balance. The adjustment to actual was $81,000. CA-101, Schedule B-1. However, the Consumer Advocate did not adjust for the beginning balance to update 2009 to the ending balance. The adjustment to account for this should have been $161,000 ($81,000 + $80,000). Settlement Exhibit at 76.

Hawaiian Electric included an estimate for state ITC earned on 2009 plant additions of $8,600,100 in the Rate Case Update. HECO T-16 Rate Case Update Attachment 3 at 5. The related deferred tax liability is $3,346,299 (8,600,100 x 38.91%). Settlement Exhibit at 76.

The Company informed the Consumer Advocate and the DOD of a legislative bill regarding capital goods excise tax credit. Settlement HECO T-16 Attachment 2 and 2A. On May 8, 2009, the Hawaii legislature passed Senate Bill No. 199, SD1, HD1, CD2, which suspends state ITC for all property placed into service in 2009. Settlement Exhibit at 77.

Hawaiian Electric, the Consumer Advocate and the DOD have agreed to remove the $8,600,100 from the 2009 additions to state ITC and the related ADIT of $3,346,299. Rate base will increase by the $8,600,100 (reduction in state ITC) and will decrease by the $3,346,299 (ADIT increase). The net adjustment to average rate base will be an increase of $2,627,000. This adjustment was conditional on the final passage of this bill into law. Settlement Exhibit at 77.

The bill became law on July 16, 2009, as Act 178. However, the statutory language did not clearly specify the cutoff date for property placed into service after such date. On August 3, 2009, the Hawaii Department of Taxation issued an announcement (No. 2009-23) that clarified April 30, 2009 as the date after which property placed into service would not be eligible for the state ITC. As indicated above, Hawaiian Electric had assumed that December 31, 2008 would be the cutoff date and no state ITC would be earned in 2009.

The Company estimates that the state ITC earned in 2009 will be $732,000. Consequently, Hawaiian Electric proposes to increase unamortized state ITC by $732,000 and to decrease ADIT by the related tax effect of $285,000. The net adjustment to average rate base will be a decrease of $223,500 (50% of the net adjustment).

For settlement purposes, the Parties agree with the Unamortized State ITC average balance of $29,376,000, and the Company proposes to increase this balance by $366,000 (50% of $732,000), with an attendant decrease in ADIT of $142,500 (50% of $285,000).

It is Hawaiian Electric's position that the Final Decision and Order should approve an Unamortized State ITC average balance of $29,376,000, as adjusted for the 2009 state ITC. Motion for Second Interim Increase Exhibit 1 at 4. With the proposed adjustment to the Unamortized State ITC as described above, the Company proposes an increase in the Unamortized State ITC by $366,000 (50% of $732,000), resulting in an average Unamortized State ITC balance of $29,742,000 ($29,376,000+$366,000).

g. Unamortized Gain on Sales

The estimated average unamortized gain on sales balance for test year 2009 in direct testimony and in the Company's Rate Case Update was $1,055,000. HECO 1801(c); HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65. In this rate base calculation, unamortized gain on sales includes the unamortized lease premium balance. HECO T-18 at 44; HECO-1801.

As described above in Rate Base Update – 2008 Actuals, for purposes of settlement, the Company agreed to include the adjustments resulting from the introduction of 2008 year-end actuals as identified in CA-101, Schedule B-1. This results in an agreed average Unamortized

Gain on Sales for the 2009 test year of $1,046,000. Settlement Exhibit at 65 and 77.

It is Hawaiian Electric's position that the Final Decision and Order should approve Unamortized Gain on Sales for the 2009 test year in the amount of $1,046,000. Motion for Second Interim Increase Exhibit 1 at 4. With the proposed adjustment to the Unamortized State ITC as described above, the Company proposes an increase in the Unamortized State ITC by $366,000 (50% of $732,000), resulting in an average Unamortized State ITC balance of $29,742,000 ($29,376,000+$366,000).

h. Pension Regulatory Asset (Liability)

In direct testimony and in the Company's Rate Case Update, the estimated average pension regulatory liability balance for test year 2009 was $2,746,000. HECO T-18 at 44; HECO-1801; HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65.

The Consumer Advocate adjusted the Pension Regulatory liability – NPPC vs. NPPC in rates based on the current estimates for 2009 received from the Company's actuary, Watson Wyatt Worldwide which reflected the pension plan asset values as of December 31, 2008. C-101 Schedule B-2. For settlement purposes, the Parties agreed upon an estimated average pension regulatory liability balance for test year 2009 in the amount of $(202,000). Refer to Regulatory Assets (Liability) – NPPC vs. NPPC in Rates above for further discussion. Settlement Exhibit at 65 and 77.

It is Hawaiian Electric's position that the Final Decision and Order should approve an estimated average pension regulatory liability balance for test year 2009 in the amount of $(202,000). Motion for Second Interim Increase Exhibit 1 at 4.

i. OPEB Regulatory Asset (Liability)

In direct testimony and in the Company's Rate Case Update, the estimated average OPEB regulatory liability balance for test year 2009 was $700,000. HECO T-18 at 46; HECO-1801; HECO T-23 Rate Case Update Attachment 7 at 3; Settlement Exhibit at 65..

The Consumer Advocate adjusted the OPEB Regulatory asset (liability) – NPBC vs. NPBC in rates based on the current estimates for 2009 received from the Company's actuary, Watson Wyatt Worldwide which reflected the OPEB plan asset values as of December 31, 2008. C-101 Schedule B-2. For purposes of settlement, the Parties agreed upon an estimated average OPEB regulatory liability balance for test year 2009 in the amount of $605,000. Settlement Exhibit at 65. Refer to Regulatory Assets (Liability) - NPBC vs. NPBC in Rates above for further discussion. Settlement Exhibit 77.

It is Hawaiian Electric's position that the Final Decision and Order should approve an estimated average OPEB regulatory liability balance for test year 2009 in the amount of $605,000. Motion for Second Interim Increase Exhibit 1 at 4.

3. <u>CIP CT-1 project</u>

a. <u>Recovery of Costs for CIP CT-1</u>

<u>Application</u>

One of the primary drivers for this rate case was to provide the vehicle for the recovery of revenue requirements arising out of the addition of Hawaiian Electric's new generating unit, CIP CT-1. Of the revenue increase of approximately $97 million requested in the Application filed July 3, 2008, approximately $23.9 million was included in the requested CIP CT-1 step increase to be effective when the generating unit was placed in service. HECO-101 at 3; HECO T-1 at 6-7.

Hawaiian Electric's revenue requirements in its Application were based on including the "full" cost of CIP CT-1 (as estimated at the time of the Application), and Hawaiian Electric proposed an interim step increase that did not include the CIP CT-1 cost, and a later step increase when CIP CT-1 went into service at the end of July 2009 that was based on the full incremental cost of adding CIP CT-1 (excluding depreciation, which does not begin until the following year).[21]

The purpose of the CIP CT-1 Step Increase was to enable the Company to recover the full cost of CIP CT-1 after the generating unit went into service. (The CIP CT-1 Step Increase was equal to the difference between the revenue requirement reflecting the full annualized cost of CIP CT-1 [with the net investment of CIP CT-1 in both the beginning and end of test year balances] and the revenue requirement exclusive of the cost of CIP CT-1.)

Settlement Agreement

The Consumer Advocate and the DOD opposed inclusion of the "full" cost of CIP CT-1 in revenue requirements, and proposed that a fully average test year be used. Based on the joint decoupling proposal of the Company and the Consumer Advocate in Docket No. 2008-0274 (Decoupling Docket), which incorporated a revenue adjustment mechanism rate base adjustment in 2010 that included actual year-end 2009 plant balances (as well as conservatively estimated plant additions in 2010), Hawaiian Electric (as part of the global settlement agreement) agreed to the use of the fully average test year, without a separate CIP CT-1 Step Increase or annualized ratemaking treatment of CIP CT-1 costs. Stipulated Settlement Letter at 90.

In addition, as part of the settlement negotiations, Hawaiian Electric reduced its Production O&M expenses by $105,000 as stated in the Company's responses to the Consumer Advocates information requests:

[21] HECO-101 at 4.

- $49,000 from Production Operations non-labor expense for CIP CT-1 Waste Water Treatment Chemicals as stated in Hawaiian Electric's response to CA-IR-297;

- $42,000 from Production Operations non-labor expense for CIP CT-1 Boiler Water Treatment as stated in Hawaiian Electric's response to CA-IR-297;

- $14,000 from Production Operations non-labor expense for CIP CT-1 Demin/Evap Chemicals as stated in Hawaiian Electric's response to CA-IR-468.

Stipulated Settlement Letter at 29.

Interim D&O

In its Interim Decision and Order issued July 2, 2009 ("Interim D&O"), the Commission excluded the revenue requirements arising out of the capital and operations and maintenance ("O&M") costs for CIP CT-1from the interim rate increase, stating that:

> The commission is concerned that HECO's CT-1 unit is not currently "used and useful." To allow HECO to recover costs associated with CT-1 as of July 2009, prior to it becoming "used and useful" is inappropriate and inconsistent with Decision and Order No. 23457, filed on May 23, 2007. In addition, the commission is concerned that CT-1 may not be operational by the end of the 2009 test year because the fuel supply contract has not been resolved. The record is currently insufficient to demonstrate that the CT-1 unit will be in service by the end of the 2009 test year.

In response to the Interim D&O, Hawaiian Electric submitted, on July 8, 2009, revised schedules and explanations of certain adjustments to the Company's 2009 test year estimates. With respect to Section II.2.(a) of the ID&O, Hawaiian Electric made adjustments to Net Cost of Plant in Service, Production Operations and Maintenance Costs, Fuel Inventory, and Accumulated Deferred Income Taxes.

Motion for Second Interim D&O

By motion filed November 9, 2009, Hawaiian Electric requested that the Commission issue a second interim decision and order as soon as possible authorizing an additional interim increase in revenue in the amount of $12,671,000,[22] which represents the revenue requirements for the Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1") Project that were included in the Settlement Agreement between the Parties filed May 15, 2009 ("Settlement Agreement"), but were not included in the first interim increase in revenue of $61,098,000 authorized by the Interim Decision and Order filed July 2, 2009, and Order Approving HECO's Revised Schedules filed August 3, 2009.[23] In the alternative, if the Commission determined that the capital costs for CIP CT-1 should not be included in rate base at this time as either "used or useful" Plant in Service, or as Property Held for Future Use, then Hawaiian Electric requested that the Commission allow the Company to accrue an Allowance for Funds Used During Construction ("AFUDC") on the components of the CIP CT-1 Project that have been transferred to Plant in Service.

The CIP CT-1 generating unit project is intended to provide three significant attributes: (1) to address the reserve margin shortfall situation; (2) to provide blackstart capability in the event of an island-wide blackout; and (3) to provide biofueled peaking generation.

With respect to the first attribute, CIP CT-1 is connected to the grid and available to serve customers in circumstances permitted by the Commission.[24] (I.e., the generating unit is actually installed and operational, although it has been run only for testing and emergency use.) With respect to the second attribute, the blackstart units are in service. With respect to biodiesel, the Company has moved aggressively to rebid the contracts, to file the test fuel contract, to take the risk of purchasing the first contract amount without prior approval (which potentially means that

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[22] As shown on Exhibit 1, page 1 to its Motion. In its requested interim relief, Hawaiian Electric is not requesting that any biofuel inventory for CIP CT-1 be included in the 2009 test year fuel inventory.

[23] In effect, Hawaiian Electric requests that the amount of the interim increase in revenue be increased from $61,098,000 to $73,769,000. See Exhibit 1, page 1, to HECO's Motion.

[24] In its Imperium D&O, the Commission noted that its order approving the stipulation requires Hawaiian Electric to operate CT-1 using only 100% biofuel, and "reminds HECO that it cannot operate CT-1 using a fuel other than 100% biofuels, absent prior approval of the commission." Id. at 5 n.5, citing Decision and Order No. 23457 at 2.

it would not be able to recover that amount if the test fuel contract is not approved), and to show the Commission the clear path the Company has to the second operational fuel contract.[25]

Given these developments, the Motion noted that there are three options for the Commission to allow the Company to earn a return on its investment in CIP CT-1 at this time:

(1) Option one – approve a second interim increase now on the basis that the unit is properly included in plant in service, and is used and useful given the first two attributes. The amount of the second interim would be $12.7 million, which includes the rate base related revenue requirements of about $11 million, and expense related revenue requirements of about $2 million.

(2) Option two – approve a second interim increase now on the basis that the unit is still property held for future use, because an operational supply of biodiesel has not yet been obtained. (Under this option, the CT-1 capital cost would be in rate base as property held for future use, but depreciation should not start until 2011 – after the operational supply of biodiesel is approved and obtained).

(3) Option three – allow the Company to reclassify the costs of the project included in plant in service to construction work in progress ("CWIP") and to accrue AFUDC until an operational supply of biodiesel is obtained, and to allow a second interim later when the operational supply of diesel is obtained.

Option one is the preferred option, and is consistent with case law holding that (1) property that services current needs, or both current and future needs, should be included in rate base as utility plant in service;[26] and (2) generation held for reserve, standby or emergency

[25] See further discussion in the Statement of Facts attached to the Motion.
[26] See Part II of the Memorandum of Law attached to the Motion.

capacity has been deemed to be used and useful for utility purposes.[27] Option two reaches the same result,[28] but requires securing of an operational supply of biodiesel for the unit before it can be included in plant in service. Option three presents complications, but would compensate the Company for the carrying cost of the investment.

The amount of the second interim increase under Option 1 or Option 2 would be the same, and would be equal to the proposed interim revenue requirements for CIP CT-1 included in the settlement agreement (with the exception that Hawaiian Electric is not requesting that any biofuel inventory for CIP CT-1 be included in the 2009 test year fuel inventory).[29]

The motion notes that the settlement is based on the average rate base concept, and does not provide for the full recovery of CIP CT-1 costs. The contemplated mechanism for recovering the remainder of the costs is through the Revenue Adjustment Mechanism ("RAM") included in the Joint Decoupling Proposal submitted by the Hawaiian Electric Companies and the Consumer Advocate in Docket No. 2008-0274. If the proposed RAM (or a similar mechanism) is not approved for implementation in 2010, then Hawaiian Electric plans to submit another motion requesting recovery of such costs in this docket.

In Option 2, the costs of the CIP CT-1 project would be included in Property Held for Future Use until the operational supply of biodiesel is approved and obtained, at which time the costs would be placed in plant in service. Since that is not expected to occur until 2010, depreciation of the depreciable costs for the project would not be expected to begin until 2011. (Including the capital costs for the project in Property Held for Future Use should not affect the

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[27] See Part III of the Memorandum of Law attached to the Motion. Accordingly, if CIP CT-1 is not included as plant in service, then CIP CT-1 should be included as property held for future use, as discussed in Part IV of the Memorandum of Law attached to the Motion.
[28] See Part V of the Memorandum of Law attached to the Motion.
[29] See Part I of the Statement of Facts attached to the Motion.

amount of the interim increase, however, since the interim increase should still include the costs of staffing and maintaining the unit to have it available for use in an emergency.)

In Option 3, the accrual of AFUDC would be discontinued when an operational supply of biodiesel is obtained and the project costs are transferred again into plant in service. At that time, Hawaiian Electric would have to file a motion to include the "full" CIP CT-1 costs in interim rates to avoid a gap in earning a return on the costs. The full costs would be limited in this proceeding to the test year estimate, despite the accrual of additional AFUDC.

On December 1, 2009, the Consumer Advocate filed Comments on HECO's Motion, in which the Consumer Advocate stated that it did not object to HECO's request for an additional interim increase of $12,671,000 representing revenue requirements for the Campbell Industrial Park Combustion Turbine Unit Project pursuant to HECO's proposals offered as Options 1 and 2. The Consumer Advocate objected to HECO's proposed alternative relief in the form of continued AFUDC for the CT-1 investment.

b. CIP CT-1 Project Status and Test Year Cost Estimate

The status of the Campbell Industrial Park Generating Station and Transmission Addition Project ("CIP CT-1 Project"), and the test year costs for the CIP CT-1 Project, are covered in the Statement of Facts attached to the motion, and are summarized in Exhibit B to this Opening Brief. Since the filing of the motion on November 9, 2009, developments with respect to CIP CT-1 (which have been reported in other on-going dockets, as summarized in Exhibit B) have included completion of the water treatment system, successful completion of biodiesel testing, and filing of the application for the two-year operational supply of biodisel.

c. CIP CT-1 Project Cost Issue Raised in Interim D&O

The Commission's Interim D&O identified cost overruns on CIP projects as one of several issues meriting additional examination prior to the final decision in this docket. IDO at 14. The Commission indicated that,

> According to HECO's most recent update on cost estimates for the CT-1 project, HECO estimates substantial cost overruns for the CT-1 project. The commission is concerned about the lack of justification in the record relating to the cost overruns for CT-1 and other CIP projects.

IDO at 14.

On October 12, 2009, the Commission identified CT-1 cost overruns as one of the issues that would be covered in its panel hearing. Letter from Commission to Parties dated October 12, 2009. The panel hearing on cost increase on CIP projects, Panel 5, was held on October 27, 2009. Tr. (Vol. II) at 467-505 (Isler).

i. <u>CIP CT-1 Cost</u>

The cost of CIP CT-1 included in this rate case was $163,279,651, as shown in HECO-S-1701. The CIP CT-1 Project cost has exceeded the cost estimate presented in Docket No. 05-0145, in which the Commission approved the commitment of expenditures. The Company's interim final cost report submitted October 2, 2009 in Docket No. 05-0145 shows an increase in the CIP CT-1 project to $193 million. This is the current cost estimate to complete the CIP CT-1 Project. HECO ST-17A at 2; HECO ST-17B at 15; Tr. (Vol. II) at 469 (Isler). A detailed breakdown of the estimated costs for each separate component project is shown in HECO-S-17A01 and in the cost report submitted in Docket No. 05-0145. HECO ST-1 at 25-26.

As discussed in more detail below, there are a number of reasons why the actual costs are higher than the costs estimated at the time the Commission approved the commitment of funds for the CIP CT-1 Project. Several factors combined to create a "perfect storm" of adverse circumstances that increased the costs for the CIP CT-1 Project. HECO ST-17E at 6. The evidence does not suggest that the Company incurred costs for the project that it should not have incurred, nor does the evidence suggest that the Company incurred costs that could have been prudently avoided.

ii. The Increased CIP CT-1 Cost

Most of the CIP CT-1 project cost increases above the original estimate were caused by the material costs and construction costs for CT-1 being higher than originally estimated. These two categories account for $53,200,000 of the $55,700,000 difference, or 96% of the increase. HECO ST-17A at 2; Tr. (Vol. II) at 468-92 (Isler).

Increased Material Costs

The estimated material costs for the generating station project are currently about $15,000,000 higher than the original cost estimate amount (i.e., approximately $65,000,000 versus approximately $50,000,000). HECO ST-17A at 2-3; HECO-S-17A02. In general, the cost variances for the materials for the CIP CT-1 Project can be categorized as:

1. Items for which the actual prices were significantly less than estimated.
2. Items for which the actual prices were very close to the original estimate.
3. Items for which the scope did not change, but the actual prices were significantly higher than estimated.
4. Items for which the scope did change and the actual unit prices were significantly higher than estimated.
5. Items which were not included in the original estimate.
6. Items which were included in the original estimate, but deleted from the final scope.

HECO ST-17A at 3; Tr. (Vol. II) at 482-92 (Isler). The increases in categories three, four and five above are attributable to a number of unusual market conditions that resulted in material and construction labor cost escalations beyond the normally expected annual price escalation. HECO ST-17A at 5; HECO-ST-17B at 5 – 10; HECO-S-17A02.

The CT-1 Project included items for which the scope did not change, but the actual prices were significantly higher than estimated, and more than half of the $9,976,000 cost increase in this category (i.e., Category 3) over the original estimate is attributable to the combustion turbine and transformers. HECO ST-17A at 5-13; HECO-S-17A02.

The CT-1 Project also involved items for which the scope did change and the actual unit prices were significantly higher than estimated, and the $5,312,000 cost increase in this category (i.e., Category 4) is attributable spare parts, higher than estimated unit prices, and increases in scope. HECO ST-17A at 13-14; HECO-S-17A02.

Finally, cost increases for the CT-1 Project are also attributable to items which were not included in the original estimate (i.e., Category 5). HECO-S-17A02 lists amounts as allowances for these items, which are subject to change. Hawaiian Electric will take measures to ensure that it receives the best reasonable cost for these items. The total for these new items is $1,188,000. HECO ST-17A at 15; HECO-S-17A02.

Increased Construction Costs

The current estimate for the generating station construction cost is $80,100,000 compared to the D&O estimate of $41,600,000. This is an increase of $38,500,000 over the original estimate. HECO ST-17A at 15; HECO-S-17A01; HECO-S-17A02. Hawaiian Electric provided detailed explanations of why the current costs differ from those originally estimated. HECO ST-17A at 15-21; HECO-S-17A01; HECO-S-17A02. Increased construction costs are attributable to cost variances for the substructure installation, foundations, ductruns, civil work, electrical balance of plant equipment, field erected tanks, buildings, combustion turbine erection, stack construction, indirects and change orders . HECO ST-17A at 15-31; HECO-S-17A01; HECO-S-17A02; Tr. (Vol. II) at 477-82 (Isler).

iii. Cost management measures taken for the CIP CT-1 Project

Hawaiian Electric effectively managed material costs for the CIP CT-1 Project. For the major pieces of equipment purchased by Hawaiian Electric, Hawaiian Electric used a competitive bid process to secure the lowest reasonable prices for materials. Hawaiian Dredging also competitively bid the equipment they were contracted to procure and passed on actual cost plus a 10% markup to Hawaiian Electric. HECO ST-17A at 33; Tr. (Vol. II) at 472-73 (Isler).

Hawaiian Electric also effectively managed construction costs for the CIP CT-1 Project through a competitive bid selection process, and then working with the selected construction general contractor, engineering consultant and the general contractor to ensure the engineering design could be built in an efficient manner. Finally, Hawaiian Electric engaged in an open-book process with the construction contractor to ensure that the contract prices were reasonable. HECO ST-17A at 33.

The Company's selection process for its construction contractor aided in effectively managing costs. Hawaiian Electric used a design-assist model, starting out by selecting a construction contractor to perform a design-assist role for the project. HECO ST-17A at 33-34. Based on their proposals and target prices, Hawaiian Electric chose Hawaiian Dredging as the design-assist contractor. HECO ST-17A at 34-35.

The Company also effectively minimized the generating station construction costs by negotiating and working closely with the selected contractor to identify other cost savings opportunities. HECO ST-17A at 35-36.

iv. <u>Overview of the cost estimating process used by the Hawaiian Electric Power Supply Engineering Department.</u>

<u>Project Cost Estimates are Ordinarily Developed During Different Phases of a Project</u>

Hawaiian Electric Power Supply Engineering is responsible for engineering and managing projects involving Hawaiian Electric's generating stations for which capital expenditure applications pursuant to General Order No. 7, paragraph 2.3(g)(2) are required.

HECO ST-17A at 42. Project cost estimates continue to be refined and updated as the project proceeds through the major phases of the project, HECO ST-17A at 42-43; Tr. (Vol. II) at 493-98 and 505 (Isler), and the actual purchase of equipment helps with the accuracy of cost estimation and further refinement of engineering of the project. HECO ST-17A at 43-44. Under *its processes at the time, the Company did all it could to make its $137 million estimate accurate.* Tr. (Vol. V) at 798 (Alm).

External Factors Caused Costs to Vary from Estimates

There are many factors that may cause the actual project cost to vary from the estimated project cost. These include permitting and regulatory approvals, schedule changes, work scope changes, commodity prices, limited availability of skilled craft labor, construction industry conditions, general market conditions, and escalation. HECO ST-17A at 45-49.

A major factor that contributed to the cost increases for the CIP CT-1 Project above the original estimate was the relatively early stage of project development at the time the original estimates were required for input to the regulatory process. In the case of the CIP CT-1 Project, there was a four year time period between the time the Company filed its application and the in-service date of the CT-1 unit. The original estimate was based on the best information available at that time but that there were numerous changes from the assumptions used for the original estimate. HECO ST-17E at 6-7.

Schedule changes can impact actual costs. If the actual schedule differs from the assumed schedule, this may lead to a variance in the project costs since changes in schedule can affect project costs. HECO ST-17A at 46. For example, allowance for funds used during construction ("AFUDC") cost has a direct correlation with the schedule. A longer schedule can increase AFUDC. The estimated amount of AFUDC for a month for costs in Construction Work in Progress ("CWIP") of $168 million is $1,148,000, and its earnings impact is approximately $1 million. HECO ST-11 at 24; Tr. (Vol. II) at 486-87 (Isler).

<u>Development of the Company's Cost Estimate for CIP CT-1 Project</u>

The Commission approved Hawaiian Electric's application to commit funds for the purchase and installation of the CIP Projects in Decision and Order No. 23457 ("D&O 23457"), filed May 23, 2007. HECO ST-17A at 49. For the CIP CT-1 Project, Hawaiian Electric hired Sargent & Lundy to complete the conceptual engineering design for the generating station and to provide a cost estimate for the project. Sargent & Lundy prepared a bottom-up method cost estimate for the CIP CT-1 Project. HECO ST-17A at 49-50.

<u>The Company's Use of Early Stage Order-of-Magnitude Cost Estimating</u>

The first step in the process for preparing cost estimates for new generating unit projects is to prepare a rough order-of-magnitude cost estimate that is subsequently refined as the project progresses and additional project information is developed. A rough order-of-magnitude cost estimate is generally prepared with only a preliminary layout, a summary-level single line diagram, and possibly preliminary flow diagrams for major systems. HECO ST-17B at 2-3. At this stage of the project, equipment sizes and costs are generally scaled from other projects with similar technology. Quantities for foundations, steel, piping, cable, conduit and raceways, valves, and instruments are based on scaling from other projects with similar technology, or from in-house databases. Labor cost estimates are based on cost estimates or reports for other projects, and average published productivity and labor rate data for a particular geographic region. HECO ST-17B at 3-5.

<u>Market Factors Affected Power Industry Costs Between 2005 and 2008</u>

Various market factors affected power industry costs between the years 2005 to 2008, including a number of unusual market conditions that resulted in material and construction labor cost escalations beyond the normally expected annual price escalation. HECO ST-17B at 6-7. If the Company had known that the actual costs would be higher, the outcome would not have changed, because the drivers for the higher costs would have impacted the costs of the other alternatives in the same way. Some of these conditions are summarized below:

Demands on National Labor Pool

Major reconstruction and rebuilding programs following major hurricanes such as Katrina in August 2005 in the southern U.S. mainland significantly increased the demands on the national labor pool. New power plant construction to meet national need for increased power generation combined with increased construction of major air quality control projects for solid fuel plants further increased the demands on the national labor pool. The contractors' need to attract and retain labor caused labor costs to escalate, and these types of non-labor rate escalations are not typically captured in industry indices, as they vary with market conditions. HECO ST-17B at 6-7.

Future Labor Concerns

By the third quarter of 2006, concerns about the availability of labor into the future caused many major construction contractors, who had previously been willing to competitively bid projects on a firm price basis, to refuse to provide firm price proposals for labor costs, and instead submit cost proposals based on a time-and-material approach. Many power industry owners were agreeing to contract terms in order to lock in a contractor, and secure the construction labor that they needed during a given time frame. HECO ST-17B at 7-8.

Concomitant Increase of Indirect Costs

Indirect costs for a construction project are generally estimated as a percentage of the overall construction cost, with the percentage value determined by market conditions. When the overall construction costs increase, indirect costs will increase proportionately. HECO ST-17B at 8.

2008 All-Time High Prices

Strong demand and stagnant supplies for commodities in the global market, as well as the U.S., drove prices to all-time highs in 2008. Material prices began escalating at higher than expected rates in late 2005, and continued on a steady rapid climb through mid-2008. HECO ST-17B at 8-10.

Cost Estimates for Labor

The original combustion turbine installation labor cost estimate for the CIP CT-1 Project was based on past labor hour estimates for projects in a similar size range, and for General Electric ("GE"), rather than Siemens, turbines because the U.S. installation experience is much greater for GE turbines. HECO ST-17B at 10. The basis for the actual combustion turbine installation labor cost increased over the original cost estimate because installation labor costs were based on a full accounting of all actual equipment, a full understanding of ancillary components furnished by the turbine supplier, a final arrangement of the combustion turbine/generator plant that included a raised inlet filter, and a finalized construction sequence and schedule that included an accurate accounting of heavy equipment and indirects. Actual labor costs are also based on the actual market conditions noted above. HECO ST-17B at 10-11.

The basis for the original estimate for foundation quantities for the CIP CT-1 Project was also scaled from other projects involving GE machines. The Siemens equipment required a significantly larger foundation than previous GE projects, due to a significantly more stringent vibration requirement. Further refinement of foundation requirements for the buildings resulted in larger foundations than assumed in the rough order-of-magnitude cost estimates. HECO ST-

17B at 11.

Costs for civil engineering and sitework increased because the cost estimates for these items were prepared before the berm work was designed. As the design was developed, parts of the site were found to be too narrow for the assumed berm design, so a 2,000 linear foot concrete wall was added in lieu of earthwork, at a significantly higher cost. HECO ST-17B at 11-12.

The actual electrical duct bank quantities for the CIP CT-1 Project were higher than originally estimated, due to requirements determined by the layout and design criteria. Requirements for duct banks to serve the administration/control building, the closed cooling water heat exchanger, and other equipment across the site were developed after the layout and equipment requirements were finalized. HECO ST-17B at 11-12.

There was a difference in the actual cable quantities required for the CIP CT-1 Project also increased because the CIP CT-1 Project require a higher degree of redundancy and automation than other simple cycle projects, in order to accommodate reliability requirements due to its island location, remote operation requirements, black start capability, and the requirement for three separate sources of water. HECO ST-17B at 12-13.

Refinements to the design criteria elements also affected the cost estimate for the CIP CT-1 Project. The following design criteria elements, defined significantly later than the 2005 cost estimate, had an impact on the actual quantities and costs of the project: the degree of redundancy, reliability, and automation required; definition of water treatment system requirements; definition of black start and remote start criteria after the original estimate; definition of design criteria such as foundation criteria and the results of the process hazards analysis, and the labor to install these requirements; the requirement for flexibility of operation to use water tanks interchangeably; and the purchase of equipment, which defined foundation, piping interface, and electrical interface requirements, and labor to install. HECO ST-17B at 13-14.

In conclusion, to improve cost certainty essentially requires spending more time and money earlier to complete more engineering design (i.e. defining the specifications and scope of work in more detail to achieve better cost estimates). That was not an option, since Commission approval was a critical path, and the application could not be delayed. Also, the changed circumstances with respect to market conditions for construction contracts, and for equipment and materials used in construction, which affected projects all over the country, were not known until late in the process.

4. KBPH Pipeline

In HECO T-17, Ms. Nagata describes the history and reasons for the construction of the Kalaeloa Barbers Point Harbor ("KBPH") pipeline in 1991. Its cost of $517,000 is included as an asset in the Company's Property Held for Future Use, which is a component of the Company's rate base. At the prehearing conference held on October 19, 2009, the Commission advised the parties that the hearing would also include questions and discussion on the KBPH pipeline, and in the Prehearing Conference Order filed on October 20, 2009, the Commission included the KBPH pipeline topic to be covered in the CT-1 Panel.[30] In the panel hearings held on October 28, 2009, both the Consumer Advocate's consultants and the Company's witnesses, Mr. Ken Morikami (who had been the witness supporting the KBPH pipeline issue in the 2007 HECO rate case, Docket No. 2006-0386) and Ms. Nagata, were questioned regarding the continued inclusion of this asset in rate base.[31]

As stated during the panel hearing, the Consumer Advocate's consultant reviewed a copy of the feasibility study for the KBPH pipeline during the discovery phase of the Company's 2005

[30] Prehearing Conference Order, filed October 20, 2009, at 6.
[31] Tr. (Vol. III) at 545-557 (Nagata).

test year rate case[32] (Docket No. 04-0113). In Interim Decision and Order No. 22050, the Commission allowed the inclusion of the KBPH pipeline in property held for future use, as reflected in the Stipulated Settlement letter between the parties filed September 16, 2005. In the Stipulated Settlement letter, at Exhibit II, page 9, the Company agreed to prepare and present a cost/benefit analysis of this investment as part of its evidence in the next rate case (i.e., the 2007 test year rate case). The Consumer Advocate's consultant also explained that he reviewed the analysis that was filed in the 2007 test year rate case with respect to the value of the asset[33] in compliance with the Stipulated Settlement letter and did not file testimony opposing its rate base inclusion.[34]

In the instant proceeding's panel hearing, the Consumer Advocate and the Company's witness agreed that, conservatively, approximately $850,000 of revenues have been collected over the 17 year period between the time of construction in 1991 and present (2009) which represents the "return recovery"[35] or revenue requirement for the KBPH pipeline during that period.[36] However, as noted by the Commission's consultant, the KBPH pipeline has been earning a return but has not been depreciated, thus no recovery of the asset itself has taken place.[37] As a result, the Consumer Advocate's consultant agreed that the Company's shareholders have not had an opportunity to reinvest their original investment in the KBPH pipeline to earn returns at possibly higher levels in their own investments.[38]

In HECO-1607, filed in the 2007 test year rate case, the Company admitted that there was no definite plan for the use or commercial operation of the property. This is still the current

[32] Ibid at 548.
[33] Ibid at 551-552.
[34] Ibid at 552-553.
[35] Ibid at 549.
[36] Ibid at 551 and 555.
[37] Ibid at 548-549.
[38] Ibid at 556.

situation. However, as described in that document, the KBPH pipeline was constructed in 1991 under unique circumstances to minimize or avoid future high infrastructure costs if it were determined that the Company would require a pipeline and is a minimal investment to preserve the Company's fuel procurement options which may facilitate the use of biofuels, supporting the Hawaiian Electric Companies' fuel independence by minimizing reliance on Oahu-based refineries. With the construction of CIP CT-1, the KBPH pipeline is a possible gateway for imported fuel to Hawaiian Electric's Barber's Point Tank Farm ("BPTF"). It has the ability to increase the number of fuel grades or types which the Company can receive, store, and consume within BPTF and may be used in negotiations for fuel contracts with Oahu-based refineries. Maintaining as many options for the Company to implement strategies as part of the Hawaii Clean Energy Initiative and a Fuels Infrastructure Strategic Plan, is in the best interests of the ratepayers. Given the minimal cost of the KBPH pipeline, its continued inclusion in the Company's rate base for future use is reasonable and appropriate.

5. Rate Base Calculation Methodologies

In the Interim D&O, the Commission requested that the Parties file testimony regarding "whether averaging the rate base at the beginning and end of the test year is appropriate or whether HECO should employ other methodologies, such as thirteen-month averages, to calculate the rate base." IDO at 19. In response, Hawaiian Electric noted that the simple average rate base is the standard in Hawaii, has been used in rate cases going back at least 30 years, and although an average test year was used in the 1970's and 1980's in order to provide some offset to the effects of attrition caused by external factors such as high inflation or regulatory lag, an average test year has not been used since due to the known inconsistency with the "matching" principle in rate-making. See HECO ST-1 at 27.

The use of 13-month averages is referred to as a weighted average rate base. It is easier to use in the case of an historic test year, since the exact timing of plant additions is known. In addition, the rate base results using a simple average rate base and a weighted average rate base may differ in the case of large capital additions. This has not necessarily been a problem in prior rate cases, where the costs associated with large plant additions were included in step increases, which can more precisely time cost recovery for such additions with the in-service dates for the units. HECO ST-1 at 28.

Moreover, in this case, there was certainly no "unfairness" in the "end result" to ratepayers in the use of an average rate base, even though most of the CIP CT-1 project was not scheduled to be in service until the end of July, since the interim rates incorporating the test year results would not go into effect until the beginning of July (rather than the beginning of the test year). See HECO ST-1 at 28-29.

V. COST OF CAPITAL

A. SUMMARY

The fair and reasonable cost of common equity ("ROE") for Hawaiian Electric (as determined by Dr. Morin) is at least 10.75%, assuming the cost recovery mechanisms identified in the Energy Agreement are implemented, and is 11% or higher if they are not. Based on Hawaiian Electric's estimated ROE of 10.75% and the settled components of the Company's cost of capital discussed below, Hawaiian Electric's estimated composite cost of capital for the 2009 test year is 8.59%. See HECO Hearing Exhibit 7 at 1; HECO Hearing Exhibit 8 at 1.[39]

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[39] In direct testimony, the Company recommended an ROE of 11.25%. This resulted in an overall cost of capital of 8.81%. HECO T-19 at 4; HECO T-20 at 65-66; HECO-2001.

The DOD estimated the equity capital cost of similar-risk electric utility companies to fall in a range of 9.25% to 10.25%, with a specific return on common equity for Hawaiian Electric of 9.50%. Using the 9.50% ROE estimate, along with the DOD's cost rate of 2.50% for short-term debt, results in an overall cost of capital of 7.84% (see DOD-105).

In testimony (CA-T-4) filed April 17, 2009, the Consumer Advocate (Mr. Parcell) recommended a range of 9.5% to 10.5% for Hawaiian Electric's ROE. Mr. Parcell recommended that the Commission reduce the authorized ROE by 50 basis points if the "HCEI-related proposals", including decoupling, were approved. Thus, he recommended that the Commission adopt the bottom of his range, 9.5%, in establishing the Company's revenue requirement in this case, if the "HCEI-related proposals" were approved, and adopt the mid-point, 10%, if the proposals were not approved. See CA-ST-4 at 3. In its determination of Hawaiian Electric's revenue requirements, the Consumer Advocate used the low point of 9.50% for ROE, resulting in an overall cost of capital of 7.86% (see CA-101, Schedule D).

Mr. Parcell submitted updated exhibits, in which he attempted to address certain of Dr. Morin's criticisms of his analyses, in CA-ST-4 filed July 20, 2009. His original recommendation was unchanged. CA-ST-4 at 4-5.

The Consumer Advocate also filed Additional Supplemental Testimony (labeled CA-AST-4) and Exhibits of Mr. Parcell, marked as CA Hearing Exhibit 3, on October 22, 2009, which Mr. Parcell presented at the Panel 13 Hearing on November 2, 2009. Again, his original recommendation was unchanged. CA-AST-4 at 3.

According to the DOD's witness, Mr. Hill, the ROE for his comparable group of electric utilities was 9.25% to 10.25%, with a mid-point of 9.75%. Based on the claim that Hawaiian Electric has less financial risk than the comparable companies (without any consideration of imputed debt), he recommended an ROE for Hawaiian Electric of 9.5%. DOD T-2 at 44-45, 50. Using the 9.50% ROE estimate, along with the DOD's cost rate of 2.50% for short-term debt, resulted in an overall cost of capital of 7.84% (see DOD-105).

All issues regarding the determination of the cost of capital have been settled, with the notable exception of the cost of common equity.

The Company's authorized rate of return on common equity should <u>not</u> be substantially reduced at this time, and certainly should not be reduced to 9.5%, as suggested by the cost of capital witnesses for the other Parties. Such a dramatic decrease would be particularly inappropriate at this time.

As noted in Dr. Morin's response to DOD-IR-25, the utility industry has experienced a steady escalation in risk over the past ten years, as evidenced by the steady rise in utility betas, standard deviation of returns, bond downgrades, and other measures of risk. Moreover, in these tough economic times in particular, investors are paying very close attention to the Company's ability to access cash. Hawaiian Electric's BBB rating by S&P is of particular concern because that rating puts the Company only one notch above the minimum "investment grade credit rating".

For the past three years, authorized ROEs for regulated electric utilities have slowly moved upward from among the lowest levels ordered by state utility regulators during the past two decades – tracking at 10.29% for 2006, 10.32% in 2007, and 10.34% during 2008.[40] Not surprisingly, after the global financial collapse during the Fall of 2008, early signs in 2009 point to higher authorized ROEs to help ensure the financial stability of regulated utilities, especially those which, like Hawaiian Electric, hold credit ratings within the "BBB" category. HECO RT-

[40] Edison Electric Institute, 2008 Financial Review, at 34 (provided in response to DOD-RIR-25).

21 at 2.

With regard to regulatory ROE decisions, HECO-R-2101 lists the 12 electric utility ROE findings reported by SNL Regulatory Research Associates for the first four months of 2009. As can be seen, the 9.50% recommendation by Mr. Hill and near 9.50% recommendation by Mr. Parcell fall at the bottom of the list. The average for the twelve decisions exceeds 10.50% and tracks more closely with Dr. Morin's 11.00% to 11.25% recommendation. Indeed, the six most recent regulatory determinations decided in March and April 2009 average 10.77%. HECO RT-21 at 2-3.

As stated by Dr. Morin, the ROE of 9.5% recommended by Mr. Hill for Hawaiian Electric is well outside the range of currently authorized ROEs for electric utilities in the United States and the zone of currently authorized ROEs for Mr. Hill's own sample of comparable companies. HECO RT-19 at 7, 9-12. The table below summarizes the overall average ROEs allowed for electric utilities since 2004:[41]

Electric Utility Allowed Returns 2004-2008

	2004	2005	2006	2007	2008
Average Allowed Return	10.75%	10.54%	10.36%	10.36%	10.46%
Average Utility Debt Cost	6.20%	5.67%	6.07%	6.12%	6.65%
Average Risk Premium	4.55%	4.87%	4.29%	4.24%	3.81%

Source: *Regulatory Focus*, SNL Energy Major Rate Case Decisions, January 2009.

Dr. Morin warned that Mr. Hill's recommendation of 9.5% ROE would endanger Hawaiian Electric's credit quality and given that the Company is already on negative outlook, would in all likelihood cause a credit rating downgrade. Tr. (Vol. VI) at 1004-05. Dr. Morin explained that the Company's financial metrics, which are already weak for its current BBB

[41] HECO RT-19 at 6. Updated information was presented at the hearing. HECO Hearing Exhibit 7, page 18 (RRA's Authorized ROEs through September 4, 2009).

rating, would be severely reduced by the lower ROE. He pointed out that adopting such a low ROE would not be good policy especially with the need for the Company acquire financing for large capital investments to implement state energy policy. Tr. (Vol. VII) at 1211-12.

The economic downturn has affected the cost of equity, as well as the cost of debt. Despite a contracting economy, AUS's April 2009 Monthly Report reflected an average allowed ROE for Combined Electric/Combination Electric and Gas utilities of 10.75%, and according to Regulatory Research Associates' April 2, 2009 Regulatory Focus, the average electric utility equity return authorized by state commissions in the first three months of 2009 was 10.29%, as compared to the 10.46% average in calendar-2008. However, excluding a 8.75% equity return authorized for United Illuminating in Connecticut, the average was 10.48% in the first quarter, which is actually higher than the 2008 average. HECO RT-20 at 25.

Hawaiian Electric's ROE should not be decreased during times of volatility and large bond spreads such as these, because of the risk of a potential downgrade. A downgrade of Hawaiian Electric's ratings would increase the Company's cost of capital, and thus, ultimately, the rates that customers are required to pay. The Company must continue to obtain regulatory rulings that: (1) give the Company a realistic opportunity to earn a fair return, (2) provide full cost recovery of prudently incurred costs on which the Company's investors make no profit, (3) assure cost recovery of and on necessary capital investments, and (4) provide a fair return on prudent investments. HECO RT-20 at 25-26.

Other commissions share the view that, in light of the current economy, the status quo should be maintained with respect to utility ROEs. For example, the Missouri Public Service Commission's January 27, 2009 decision in Re Union Electric Company, dba AmerenUE, Case No. ER-2008-031 provides a good example. In that rate case, the Missouri commission explained that: "Maintaining the status quo on the company's ROE in light of the economic circumstances and the U.S. credit crisis is the most prudent course of action. The U.S. credit crisis and ensuing breakdown in confidence among financial institutions has led to rising long-term borrowing rates. The freeze of the credit system causes concern for the utility's continued ability to provide financing for infrastructure investment needs, and then to continue to provide safe, reliable, and abundant power at reasonable rates. At this time, a cautious approach in changing the company's ROE is necessary to ensure investor confidence and company access to capital markets." HECO RT-20 at 26.

There is a strong relationship between financial risk and the authorized ROE. The strength of that relationship is amplified for smaller utilities like Hawaiian Electric. A low authorized ROE increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns. HECO T-19 at 60-61.

Hawaiian Electric's financial risk is impacted by the authorized rate of return on equity. A low return on equity increases the likelihood that Hawaiian Electric will have to rely on debt financing for its capital needs. As the Company relies more on debt financing, its capital structure becomes more leveraged. Since debt payments are a fixed financial obligation to the utility, this decreases the operating income available for dividend growth. Consequently, equity investors face greater uncertainty about the future dividend potential of the firm. As a result, the Company's equity becomes a riskier investment. The risk of default on the Company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the Company will not have access to the capital markets for its outside financing needs, or if so, at prohibitive costs. HECO T-19 at 61.

Reducing the "allowed" cost of common equity results in lower rates, at least in the short-term. However, Hawaiian Electric's customers cannot afford for Hawaiian Electric's cost of common equity to be understated. Hindering the ability of Hawaiian Electric to attract capital could be harmful to the economic infrastructure of Oahu, and would be contrary to the best interests of Hawaiian Electric's customers. Hawaiian Electric, unlike many other companies, cannot stop necessary investments in plant, or legislated environmental investment, when the availability of capital is constrained in the market, as it is from time to time. Customers expect service to occur on demand. Therefore, Hawaiian Electric, which provides customers with indispensable energy services, must be sufficiently strong financially to cope with unforeseen events, and its securities must be attractive enough to access capital during adverse, as well as more normal, market conditions.

It is critical to at least maintain Hawaiian Electric's current credit rating. A financially stable utility will be able to invest in new renewable resources, infrastructure to facilitate the addition of new renewable resources from independent power producers, and conversion of the existing system to renewable technologies. The Company expects to enter into numerous new purchased power agreements for renewable energy, including power purchases under the feed-in tariff. HECO RT-20 at 26-27.

There was extensive discussion of the extent to which recently proposed cost recovery mechanisms would reduce the Company's business risk, and therefore reduce its required rate of return on common equity. The mechanisms include the REIP/CEI surcharge, the proposed

Purchased Power Adjustment Clause ("PPAC"), and the proposed Decoupling Mechanism, which includes a proposed sales decoupling mechanism (to be implemented through a revenue balancing account or "RBA"), and a proposed revenue adjustment mechanism ("RAM").

The 25 basis point reduction included in Dr. Morin's recommended ROE fairly accounts for the potential impact of these mechanisms on Hawaiian Electric's ROE, taking into account the following:

> (1) The Company's business risks have substantially increased as the result of the changes to the RPS Law, adopted as a result of the Hawaii Clean Energy Initiative ("HCEI"). The cost recovery mechanisms are intended to mitigate, to the extent practical, these increased risks.
>
> (2) The market-derived cost of common equity for Hawaiian Electric is estimated by the experts from market information on the cost of common equity for other firms, including other electric utilities. Thus, if and to the extent that the market-derived cost of common equity for other firms already incorporates the results of these or similar mechanisms, then no further adjustment is appropriate or reasonable in determining the cost of common equity for Hawaiian Electric.[42]
>
> (3) The effect of these proposed mechanisms on the cost of common equity for Hawaiian Electric is already accounted for, in substantial part, by eliminating the risk differential premium of 25-50 basis points previously incorporated in determining the cost of common equity for Hawaiian Electric relative to the cost of common equity for other electric utilities.
>
> (4) The timing of the implementation of the proposed mechanisms must also be taken into account. None of the mechanisms were actually in place during the 2009 test year. This is particularly significant in the case of the proposed PPAC, which will not take effect until the Commission's final decision and order (if approved).
>
> (5) Hawaiian Electric has been found to be riskier than the proxy electric utilities used to estimate the market-derived ROE for the Company. Without the risk mitigation measures, the differential in risk would be even greater due to the additional risks resulting from Act 155. Elimination of the risk differential in determining the ROE for Hawaiian Electric, as proposed by Dr. Morin, already

[42] As Dr. Morin states in HECO RT-19, while adjustment clauses and cost tracking mechanisms are beneficial in mitigating operating risk, the approval of adjustment clauses and cost recovery mechanisms by regulatory commissions is widespread in the utility business and, in Hawaiian Electric's case, there are other significant factors to consider that work in the reverse direction for Hawaiian Electric. HECO RT-19 at 8.

accounts for much of the benefit of the new measures.

Further reducing Hawaiian Electric's allowed return based on the speculative impacts of new mechanisms that have not yet been implemented would not make sense given the Company's inability to come close to earning its authorized return in recent years, and the need to maintain and enhance the Company's credit and financial integrity.

The Company's actual rates of return on simple average common equity as filed with the Commission have been (HECO T-20 at 4):

Return on Common Equity

2005	6.92%
2006	7.61%
2007	4.52%

The Commission set interim and final rates in Hawaiian Electric's 2005 test year rate case (Docket No. 04-0113) based on a 10.7% rate of return on common equity ("ROE")[43] and set interim rates in the Company's 2007 test year rate case (Docket No. 2006-0386) based on a 10.7% ROE.[44] Hawaiian Electric's ROE in 2008 was 8.07% for ratemaking,[45] over 260 basis points lower than the authorized return of 10.7%. As of June 30, the 12 months trailing ROE was only 6.4% (on a ratemaking basis),[46] 410 basis points less than the 2009 test year interim ROE of 10.5%. As of September 30, 2009, the 12 months trailing ROE was only 6.52% (on a ratemaking basis).[47]

[43] Interim D&O No. 22050, filed September 27, 2005 in Docket No. 04-0113; Amended Proposed D&O No. 23768, filed October 25, 2007 in Docket No. 04-0113; D&O No. 24171, filed May 1, 2008 in Docket No. 04-0113.

[44] Interim D&O No. 23749, filed October 22, 2007, in Docket No. 2006-0386.

[45] Rate of Return on Rate Base and on Common Equity for December 2008 (ratemaking method), filed February 27, 2009.

[46] Rate of Return on Rate Base and on Common Equity for June 2009 (ratemaking method), filed August 7, 2009.

[47] Rate of Return on Rate Base and on Common Equity for September 2009 (ratemaking method), filed November 2, 2009.

B. HAWAIIAN ELECTRIC'S COST OF CAPITAL

1. Introduction

The Commission has held that a fair rate of return for a utility must:

> (1) Be commensurate with returns on investment in other enterprises having corresponding risks and uncertainties;
>
> (2) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
>
> (3) Provide a return sufficient to assure confidence in the financial integrity of the enterprise to maintain its credit and capital-attracting ability.

Re Hawaiian Elec. Co., Docket No. 04-0113, Decision and Order No. 24171 (May 1, 2008) at 70, citing Bluefield Waterworks and Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). See also Re Hawaii Elec. Light Co., Docket No. 99-0207, Decision and Order No. 18365 (February 8, 2001) at 63-64; Re Maui Elec. Co., Docket No. 97-0346, Amended Decision and Order No. 16922 (April 6, 1999) at 33; Fed. Power Comm'n v. Memphis Light, Gas & Water Div., 411 U.S. 458 (1973); Permian Basin Rate Cases, 390 U.S. 747 (1968); Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989).

"Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the *Fourteenth Amendment*." Bluefield Water Works & Improvement Co., 262 U.S. at 690, 43 S. Ct. at 678.

In order to meet the foregoing criteria, the fair rate of return should at least be equal to Hawaiian Electric's composite cost of capital, because the composite cost of capital represents the carrying cost of the money received from investors to finance the net rate base. See HECO

T-20 at 3.

A return on rate base at least equal to Hawaiian Electric's composite cost of capital would allow the Company to cover the capital costs of the business; would provide a return on investment commensurate with returns on other investments having corresponding risks; would provide assurances to the financial community of Hawaiian Electric's financial integrity; and would maintain the company's creditworthiness and ability to attract capital on reasonable terms. See HECO T-20 at 3.

a. Calculation of the Cost of Capital

The composite cost of capital is calculated by summing the weighted effective costs of each element of the capital structure. The capital structure is typically made up of the short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. The overall cost of each of the elements is calculated taking into account such items as issuance costs to come up with an "effective" cost for each element. The "effective" cost of each element of the capital structure is "weighted" in proportion to its percentage in the capital structure to come up with a weighted effective cost. HECO T-20 at 7.

2. Cost of Capital

a. Stipulated Capitalization

The parties are in agreement with respect to the following capitalization for Hawaiian Electric's 2009 test year:

Hawaiian Electric's Capitalization

Category	Amount ($000)	Weight (%)
Short-term borrowing	0	0.00
Long-term borrowing	576,569	40.76
Hybrid securities	27,775	1.96
Preferred stock	20,696	1.46
Common stock	789,374	55.81

See Revised Schedules Exhibit 1 at 2; Settlement Exhibit at 83.

At the time Hawaiian Electric filed its direct testimony in this docket, the Company had been anticipating a test year short-term borrowing balance of $22 million, as well as a new issuance in 2009 of $80 million in preferred stock. See HECO T-54-55, 59. As a result, the Company's direct testimony reflected the following capital structure, which was also utilized in the direct testimonies filed by the Consumer Advocate and DOD:

	Direct Testimony Capitalization	
Category	Amounts ($000)	Weight (%)
Short-term borrowing	21,951	1.49
Long-term borrowing	561,940	38.27
Hybrid securities	27,775	1.89
Preferred stock	59,496	4.05
Common stock	797,307	54.30

Settlement Exhibit at 83.

However, Hawaiian Electric modified its financing plans, and elected to pursue a common stock issuance in lieu of issuing preferred stock (see HECO RT-20 at 5), while also taking a negative short-term borrowing position. See Settlement Exhibit at 83-84; HECO RT-20 at 2-6. In its settlement proposal to the other parties, the Company thus proposed the following test year capital structure:

	Settlement Proposal Capitalization	
Category	Amounts ($000)	Weight (%)
Short-term borrowing	(22,011)	-1.58
Long-term borrowing	576,569	41.40
Hybrid securities	27,775	1.99
Preferred stock	20,696	1.49
Common stock	789,519	56.70

After discussing the timing and reasons for Hawaiian Electric's proposed negative short-term borrowing position at year-end 2008 and estimated at year-end 2009, and the impact on the before-tax and after-tax rate of return, the Parties agreed that the short-term borrowing amount would be assumed to be zero for the test year, resulting in the following settlement capital structure:

Settlement Agreement Capitalization

Category	Amounts ($000)	Weight (%)
Short-term borrowing	0	0.00
Long-term borrowing	576,569	40.76
Hybrid securities	27,775	1.96
Preferred stock	20,696	1.46
Common stock	789,519	55.81

Settlement Exhibit at 83; see HECO RT-20 at 2-6.

In the Revised Schedules, the Hawaiian Electric made a slight downward adjustment to the Company's amount of common equity from the settlement level of $789,519,000 (see Settlement Exhibit at 84) to $789,374,000 (see Revised Schedules Exhibit 1 at 1, 2) that corrected a miscalculation in the settlement amount.

b. Cost Rates

As reflected in the Revised Schedules, the parties have reached settlement with respect to the following cost rates for short-term borrowing, long-term borrowing, hybrid securities and preferred stock:

Hawaiian Electric's Settled Cost Rates

Category	Cost Rate
Short-term borrowing	0.75%
Long-term borrowing	5.81%
Hybrid securities	7.41%
Preferred stock	5.48%

See Revised Schedules Exhibit 1 at 2; HECO RT-20 at 2-6; Settlement Exhibit at 85.

In direct testimony, the Company proposed the following cost rates for the capital structure components listed above:

Direct Testimony Cost Rates

Category	Cost Rate
Short-term borrowing	3.25%
Long-term borrowing	5.75%
Hybrid securities	7.41%
Preferred stock	7.62%

The Consumer Advocate and DOD, in their direct testimonies, used Hawaiian Electric's direct testimony cost rates for long-term debt, hybrid securities and preferred stock. However, with respect to the cost of short-term debt, the Consumer Advocate and DOD used cost rates of 3.25% and 2.50%, respectively. See CA-101, Schedule D; DOD-105.

The only disputed issue between Hawaiian Electric and the other parties with respect to the cost of capital is the fair return on common equity to be used in determining the Company's revenue requirements. See Settlement Exhibit at 86. As further discussed below, the fair return on common equity for Hawaiian Electric, assuming approval of the RBA, RAM, the REIP/CEI Surcharge and the Purchased Power Adjustment Clause, is 10.75%.

c. Hawaiian Electric's Composite Cost of Capital

Based on Hawaiian Electric's estimated ROE of 10.75% and the settled components of the Company's cost of capital discussed above, Hawaiian Electric's estimated composite cost of capital for the 2009 test year is 8.59%. See HECO Hearing Exhibit 7 at 1; HECO Hearing Exhibit 8 at 1.

As discussed above, changes were made during the course of this proceeding to various components of the Company's cost of capital, which ultimately affected Hawaiian Electric's overall cost of capital estimates. In Direct Testimony, the Company estimated a fair rate of return on rate base for the 2009 test year of 8.81%, including a return on common equity of 11.25%. See HECO T-20 at 2; HECO-2001; HECO T-19 at 4. The settlement agreement capital structure and 10.5% interim ROE resulted in a settlement composite cost of capital of 8.46% for purposes of the interim rate increase. See Settlement Exhibit at 85-86. In the Revised Schedules, Hawaiian Electric utilized a slightly lower composite cost of capital of 8.45%, due to the decrease in the Company's amount of common equity and, from that corrected a miscalculation in the settlement amount, as noted above. In Rebuttal Testimony, Hawaiian

Electric updated its composite cost of capital to 8.73%, based on a rate of return on common equity of 11.0%. See HECO RT-20 at 2-6.

C. COST OF EQUITY CAPITAL ESTIMATES

In direct testimony, Hawaiian Electric's return on equity witness, Dr. Morin, recommended a return on common equity of 11.25%. See HECO T-19 at 4. The Consumer Advocate's ROE witness, Mr. Parcell, recommended a ROE in the range of 9.5% to 10.5% in his direct testimony. See CA-T-4 at 49. Mr. Hill, the DOD's ROE witness, estimated an ROE for the Company in the range of 9.25% to 10.25%, with a mid-point of 9.75%. See DOD T-2 at 44-45.

In rebuttal testimony, Dr. Morin updated his ROE estimate for Hawaiian Electric to 11.00%-11.25% assuming approval of the RBA and RAM, and 11.25%-11.50% without approval of the RBA and RAM. See HECO RT-19 at 73. For purposes of the hearing, Dr. Morin further updated his ROE estimate to the Company's current estimate of 10.75% with the revenue decoupling mechanism ("RDM")/Rider mechanisms, and 11.00% without the RDM/Rider mechanisms.[48] See HECO Hearing Exhibit 7 at 1. Although Mr. Parcell updated his ROE estimate for purposes of the hearing, Mr. Parcell's update did not result in a change to the Consumer Advocate's overall ROE recommendation for Hawaiian Electric. See CA Hearing Exhibit 3 at 3. Mr. Hill did not update his ROE recommendation subsequent to the filing of his direct testimony.

Hawaiian Electric derived its estimated fair return on common equity by employing three methodologies: (1) the CAPM, (2) the Risk Premium and (3) the DCF methodologies. All three

[48] The Company defined the RDM as the RBA and the RAM jointly proposed by Hawaiian Electric and the Consumer Advocate in the decoupling proceeding (Docket No. 2008-0274) and the "Rider" mechanisms as the Purchased Power Adjustment Clause proposed in this proceeding and the Renewable Energy Infrastructure Program ("REIP")/Clean Energy Infrastructure ("CEI") Surcharge proposed in Docket No. 2007-0416. Tr. (Vol. VI) at 1061.

methodologies are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to Hawaiian Electric. The aforementioned methodologies were applied to samples of average risk utilities representative of the electric utility industry as a whole and the results were adjusted upward to recognize Hawaiian Electric's higher relative risk. The use of multiple approaches for estimating the cost of equity is appropriate, as no one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. See HECO T-19 at 13-14.

There are difficulties in applying cost of capital methodologies in the current economic environment, as all of the traditional cost of equity estimation methodologies are difficult to implement under the fast-changing circumstances of the electric utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation, restructuring, and the transition to a more competitive environment. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. As a result, consideration of each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. See HECO T-19 at 14-16.

1. CAPM Analyses

a. CAPM

The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. The seminal CAPM expression states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). See HECO T-19 at 19-20.

The empirical version of the CAPM ("ECAPM") makes use of empirical findings that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. See HECO T-19 at 28-29.

b. Dr. Morin's Analyses

Dr. Morin performed both a standard CAPM and an ECAPM analysis. The results of Dr. Morin's CAPM analyses were as follows.

(1) Standard CAPM

(a) 11.0% in direct, HECO T-19 at 28.

(b) 9.2% in rebuttal, HECO RT-19 at 72.

(c) 9.4% in the update, HECO Hearing Exhibit 7 at 2.

(2) ECAPM

(a) 11.3% in direct, HECO T-19 at 31.

(b) 9.6% in rebuttal, HECO RT-19 at 72.

(c) 9.8% in the update, HECO Hearing Exhibit 7 at 2.

The test results include flotation costs of 0.3%, but do not include an upward adjustment for Hawaiian Electric's relatively higher risk due mainly to the Company's relatively small size and imputed debt. See HECO T-19 at 52.

As a proxy for the risk free rate of return, Dr. Morin relied on the current level of 30-year Treasury bond yields, reflecting the fact that common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. See HECO T-19 at 20-21. Significant changes occurred in capital market conditions following the preparation of Dr. Morin's direct testimony, which reduced the level of U.S. Treasury 30-year long-term bond yields from 4.6% in direct testimony to 4.0% in rebuttal testimony. See HECO RT-19 at 69.

As proxies for the beta of the electric utility industry, Dr. Morin examined the betas of two samples of widely-traded investment-grade electric utilities covered by Value Line: (1) vertically integrated electric utilities that pay dividends and with at least 50% of their revenues from regulated electric utility operations; and (2) electric utilities that make up Moody's Electric Utility Index. HECO T-19 at 23-24. Between the filing of Dr. Morin's direct and rebuttal testimonies, betas decreased from the 0.85 level to the 0.75 level. However, betas are estimated on five-year historical periods, and therefore do not capture the current increased risk environment faced by utilities. See HECO RT-19 at 69.

Dr. Morin's market risk premium (or "MRP") estimate was based on the results of both historical and forward-looking studies on long-term risk premiums. First, the Ibbotson Associates (now Morningstar) study, Stocks, Bonds, Bills, and Inflation, 2008 Yearbook, shows that the historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical MRP, as the more accurate way to estimate the MRP from historic data is to use the income return, not total returns on government bonds, as explained in Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2008 Yearbook. Second, a DCF analysis applied to the aggregate equity market using the S&P 500 Index and Value Line growth forecasts indicates a prospective MRP of 7.8%. Dr. Morin employed the average of the two estimates, 7.4%, as a reasonable estimate of the MRP. See HECO T-19 at 24-28.

Little, if any, weight should be accorded to the CAPM results under present economic circumstances for three reasons. First, the CAPM estimates in the single-digit are barely above the corporate cost of debt and are therefore suspect. Second, because the betas employed in the CAPM analysis are estimated over five-year historical periods, the impact of the ongoing financial crisis is not yet fully captured in the five-year historical betas. Third, government interest rates have decreased substantially following the Federal Reserve's expansionary policies designed to jumpstart the stalled economy, thus lowering the CAPM results. HECO RT-19 at 26; see response to DOD-RIR-48.

c. **Mr. Parcell's Analysis**

Mr. Parcell concluded in his direct testimony that the CAPM cost of equity for Hawaiian Electric is 7.5%. CA-T-4 at 42. In subsequent updates to his CAPM analyses, Mr. Parcell's CAPM estimates increased to the 8.2% to 8.4% range. However, while Mr. Parcell's CAPM estimates increased after the filing of his direct testimony, his DCF estimates decreased in his updates, and the overall impact of Mr. Parcell's updates and modifications left Mr. Parcell's original cost of equity recommendation of 9.5% to 10.5% unchanged. See CA Hearing Exhibit 3 at 4, 26; CA-ST-4 at 3-4.

As a proxy for the risk-free rate, Mr. Parcell used 3.49%, which is the average yield on 20-year Treasury bonds for the three-month period December 2008-February 2009. However, the latest Value Line issue as of the filing of Dr. Morin's rebuttal testimony (May 8, 2009) reported a yield of 4.0% on 30-year Treasury bonds. Replacing the Mr. Parcell's "stale" Treasury bond yield with the more current yield of 4.0% results in an increase to the risk free rate of 50 basis points. See HECO RT-19 at 61.

In order to determine the MRP component of his CAPM analysis, Mr. Parcell relied on three estimates. First, he examined the difference between the accounting returns on book equity (ROE) on the S&P 500 Index companies group over the 1978-2007 period and the contemporaneous level of 20-year Treasury bond yields. The average spread (MRP) was 6.45%. However, in a classic apples and oranges situation, this estimate mismatches accounting (book) returns with market (economic) returns. See HECO RT-19 at 61.

Second, Mr. Parcell relied on the long-term 5.6% historical MRP reported in the Ibbotson Associates Valuation 2009 Yearbook for the 1926-2008 period based on arithmetic averages. As discussed above, the more accurate way to estimate the market risk premium from historic data is to use the income return, not total returns, on government bonds. The long-term (1926-2008) market risk premium (based on income returns, as required) is 6.5%, rather than 5.6%.

Third, Mr. Parcell relied on the long-term 3.9% historical MRP reported in the same publication for the same period but this time based on geometric averages. From these three estimates, Mr. Parcell concluded that the MRP is 5.32%, that is, the average of the three MRP estimates. HECO RT-19 at 61. However, although arithmetic means are appropriate for forecasting and estimating the cost of capital, geometric means are not. Mr. Parcell's use of the geometric mean MRP of 3.9% rather than the arithmetic mean of 5.6% significantly understates the MRP, which suggests an understatement of Hawaiian Electric's cost of equity by 120 basis points (1.2%) using Mr. Parcell's beta for the Company of approximately 0.73. See HECO RT-19 at 63-64.

d. Mr. Hill's Analysis

In direct testimony, Mr. Hill estimated a CAPM cost of equity for Hawaiian Electric of 8.17%, although Mr. Hill notes that the CAPM analysis should not be used as a primary estimate of the cost of equity capital. See DOD T-2 at 33. In summarizing his CAPM calculation, Mr. Hill asserts that:

> DOD-212, shows that the average Value Line beta coefficient for the group of electric companies under study is 0.72. The mid-point of the range of market risk premiums published by Brealey and Meyers of 5.3% would, upon the adoption of a 0.72 beta, become a electric utility sample group premium of 3.83% (0.72 x 5.3%). That non-specific risk premium added to the recent average T-Bond rate of 3.47% yields a common equity cost rate estimate of 7.30%. Using the historical arithmetic average market risk premiums published by Morningstar (6.5%) the resulting CAPM equity cost estimate for the electric companies would be 8.17%.

DOD T-2 at 37.

2. Risk Premium Estimates

Risk Premium analyses are widely used by analysts, investors, and expert witnesses. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are well versed in the use of this method. See HECO T-19 at 32-33. In direct testimony, Dr. Morin performed two risk premium analyses: (1) a historical risk premium analysis on the electric utility industry, and (2) a study of the risk premiums reflected in ROEs allowed in the electric utility industry. HECO T-19 at 4. Risk premium analyses were not performed by Mr. Parcell or Mr. Hill.

a. <u>Historical Risk Premium Analysis</u>

In direct testimony, Dr. Morin's historical risk premium analysis resulted in an estimated ROE for Hawaiian Electric (with flotation costs) of 10.6% (based on an average risk premium of 5.7% over historical long-term Treasury bond returns and a risk-free rate of 5.7%). This estimate does not include an upward adjustment for Hawaiian Electric's relatively higher risk. <u>See</u> HECO T-19 at 52.

As a proxy for the risk premium applicable to the electric utility business, Dr. Morin's direct testimony estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using <u>Moody's Electric Utility Index</u> as an industry proxy. <u>See</u> HECO-1902. The risk premium was estimated by computing the actual realized return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. <u>See</u> HECO T-19 at 32-33.

The Company updated this estimate to 11.5% (with flotation costs) in its rebuttal testimony. As explained in rebuttal testimony, Dr. Morin's rebuttal estimate reflected two methodological changes: (1) use of the S&P Utility Index instead of the Moody's Utility Index, due to the discontinuation of the Moody's index; and (2) use of the A-rated utility bond yield instead of the government bond yield, in recognition of the fact that, whereas trends in utility cost of capital are directly reflected in their cost of debt, they are not directly captured by a risk premium estimate tied to government bond yields. HECO RT-19 at 71; <u>see</u> response to DOD-RIR-62. In HECO Hearing Exhibit 7, Dr. Morin reduced this estimate to 10.9%. <u>See</u> <u>id.</u> at 2-3.

b. Allowed Risk Premium Analysis

Dr. Morin's allowed risk premium analysis in direct testimony resulted in an implied ROE for the average risk utility of 10.2%, based on the ROEs allowed by regulatory commissions for electric utilities over the last decade (from Regulatory Research Associates (now SNL) and easily verifiable from SNL publications and past commission decision archives) relative to the contemporaneous level of the long-term Treasury bond yield. (This estimate does not include an upward adjustment for Hawaiian Electric's relatively higher risk. See HECO T-19 at 52. In addition, no flotation cost adjustment is required here because the return figures are allowed book ROEs rather than market-based ROEs. See HECO T-19 at 34.) Dr. Morin did not implement the allowed risk premium analysis for purposes of his rebuttal testimony or hearing exhibit in view of in view of the scarcity of decisions since the financial crisis began in Fall 2008. See HECO RT-19 at 71; HECO Hearing Exhibit 7 at 3; response to DOD-RIR-63; response to CA-RIR-15.

3. DCF Estimates

a. Constant Growth DCF Model

The DCF model is derived from the present value theory of investments. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional constant growth DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, and book value

HECO T-19 at 36.

The constant growth DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis. HECO T-19 at 37.

The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. HECO T-19 at 38.

b. <u>Dr. Morin's Analysis</u>

Because Hawaiian Electric is not publicly traded, the DCF model cannot be directly applied to the Company and proxies must be used. HECO T-19 at 42. Dr. Morin applied the DCF model to two proxies for the electric utility industry: (1) a group of investment-grade dividend-paying integrated electric utilities; and (2) a group consisting of the companies that make up Moody's Electric Utility Index. HECO T-19 at 37.

<u>Dividend Yield</u>

In implementing the DCF model, Dr. Morin used the dividend yields reported in the latest edition of Value Line's VLIA software. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield. HECO T-19 at 38. The average expected dividend yield in Dr. Morin's direct testimony was 4.3%. <u>See</u> HECO-1904; HECO T-19 at 45.

Growth

As proxies for expected growth, Dr. Morin examined the consensus growth estimate developed by professional analysts employed by large investment brokerage institutions and used (1) analysts' long-term growth forecasts contained in Zacks; and (2) Value Line's growth forecast.

Dr. Morin rejected historical growth rates as proxies for expected growth in the DCF calculation on the grounds that: (1) to the extent that historical growth patterns are relevant, they already have been incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant; and (2) historical growth rates have little relevance as proxies for future long-term growth at this time, as they are downward-biased by the sluggish earnings performance in the last five years caused by the structural transformation of the electric utility industry from a fully integrated regulated monopoly to a more competitive environment. See HECO T-19 at 39.

Dr. Morin also chose not to rely on the "sustainable growth" (or "retention growth") method for estimating growth for the following three reasons: First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. HECO T-19 at 41; see response to CA-

RIR-18.

In addition, Dr. Morin considered, but chose not to rely on projected dividend growth at this time, because as a practical matter, while earnings growth forecasts are widely available, there are very few dividend growth forecasts. HECO T-19 at 41.

Results

Applying Value Line's dividend yield to the Value Line and Zacks growth rates for Dr. Morin's two proxy groups, Dr. Morin's DCF study resulted in the following direct testimony DCF ROE estimates (including flotation costs, but excluding an upward adjustment for Hawaiian Electric's relatively higher risk):

Proxy Group	Growth Rate	ROE
Vertically Integrated Electric Utilities	Value Line	10.5%
Vertically Integrated Electric Utilities	Zacks	11.9%
Moody's Electric Utilities	Value Line	11.3%
Moody's Electric Utilities	Zacks	11.1%

See HECO T-19 at 47.

In rebuttal testimony, Dr. Morin increased his ROE estimates to reflect that, as of May 2009, the DCF results for the energy utilities had increased significantly by 100 basis points in response to lower stock prices (higher dividend yields) following the financial crisis. HECO RT-19 at 69-70. Dr. Morin's rebuttal DCF ROE estimates were as follows:

Proxy Group	Growth Rate	ROE
Vertically Integrated Electric Utilities	Value Line	12.3%
Vertically Integrated Electric Utilities	Zacks	12.6%
Moody's Electric Utilities	Value Line	12.0%
Moody's Electric Utilities	Zacks	12.0%

Subsequently, in Hearing Exhibit 7, Dr. Morin further updated his DCF ROE estimates as shown below, which reflect a minor departure from his original DCF analysis by using the S&P Utility Index instead of the discontinued Moody's Utility

Index. See HECO Hearing Exhibit 7 at 2.

Proxy Group	Growth Rate	ROE
Vertically Integrated Electric Utilities	Value Line	11.0%
Vertically Integrated Electric Utilities	Zacks	11.3%
Moody's Electric Utilities	Value Line	11.2%
Moody's Electric Utilities	Zacks	11.4%

Mr. Parcell's direct testimony took issue with the fact that Dr. Morin used only one indicator of growth in the DCF analysis, namely, analyst growth projections and that Dr. Morin ignored historical and projected growth rates in dividends and book value. However, it is improper to rely on "near-term" dividend growth because: (1) earnings growth drives dividend growth, (2) of the scarcity of dividend forecasts, and (3) it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years in response to increased business risk and external financing requirements, and that earnings and dividends are not expected to grow at the same rate in the future. In Dr. Morin's direct and rebuttal testimony, Dr. Morin discussed the merits of using consensus analysts' earnings growth forecasts in the DCF model and the supportive empirical literature. See HECO RT-19 at 59-60.

c. **Mr. Parcell's Analysis**

Mr. Parcell also applied the constant growth DCF model. In doing so, he combined the current dividend yield for each of four groups of proxy utility stocks with several indicators of expected dividend growth. CA-T-4 at 34.

In deriving the dividend yield component of his DCF model, Mr. Parcell utilized a quarterly compounding variant, which he expressed as follows: Yield = $D_0(1+0.5g)/P_0$. See CA-T-4 at 35. In deriving the growth component of his DCF model, Mr. Parcell considered five indicators of growth. CA-T-4 at 36. In his direct testimony, Mr. Parcell expressed a belief that "a range of 10 percent to 11 percent represents the current DCF cost of equity for HECO." CA-T-4 at 38.

In subsequent updates to his DCF analyses, Mr. Parcell's DCF estimates decreased to the 9.4% to 10.1% range. However, while Mr. Parcell's DCF estimates decreased after the filing of his direct testimony, his CAPM estimates increased in his updates, and the overall impact of Mr. Parcell's updates and modifications left Mr. Parcell's original cost of equity recommendation of 9.5% to 10.5% unchanged. See CA Hearing Exhibit 3 at 4, 26; CA-ST-4 at 3-4.

Dr. Morin identified a number of problems with Mr. Parcell's application of the DCF model as used in Mr. Parcell's testimony.

First, Mr. Parcell relied on stale stock process representing average prices over the three-month period from December 2008 to February 2009. If Mr. Parcell had used current stock prices instead of stock prices averaged over three months ending February 2009, his average DCF estimate of would have increased by 45 basis points. See HECO RT-19 at 55-56; response to CA-RIR-28.

Second, because the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year, Mr. Parcell's quarterly compounding variant understates the dividend yield by halving it. This mathematical adjustment fails to measure the full dividend flow expected by the investor and underestimates the cost of equity by approximately 20 basis points. See HECO RT-9 at 56.

Third, the results from Mr. Parcell's use of the retention growth method should be given little, in any weight in this proceeding, on the grounds that (1) implementation of the sustainable growth method, to the extent relied upon, is logically circular because it assumes a ROE in a regulatory process that is designed to estimate the fair and reasonable ROE; and (2) empirical finance literature demonstrates that the sustainable growth rate technique is a very poor explanatory variable of market value and is not correlated significantly to measures of value, such as stock price and price/earnings ratios. See HECO RT-19 at 15-17, 57.

Fourth, the historical growth rates in dividends, earnings, and book value used by Mr. Parcell as proxies for expected growth are not reliable proxies for expected future growth. If historical growth rates are to be representative of long-term future growth rates, they must not be biased by non-recurring events. This is certainly the case for electric utilities, where growing competition, diversification programs, acquisitions, restructurings and write-off activities have exerted a dilutive effect on historical earnings and dividends. In such cases, it is obvious that analysts' growth forecasts provide a more realistic and representative growth proxy for what is likely to happen in the future than historical growth. In any event, historical growth rates are somewhat redundant given that analysts formulate their growth expectations based in part on historical patterns. HECO T-19 at 57.

In addition, there are dangers in relying on Value Line as an exclusive source of forecasts in applying the DCF model, as averages of analysts' growth forecasts such as those contained in First Call and/or Zacks, rather than one particular firm's forecast, are more reliable estimates of the investors' consensus expectations likely to be impounded in stock prices. HECO T-19 at 58. Moreover, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. HECO T-19 at 58; see response to CA-IR-15.

d. Mr. Hill's Analysis

In his direct testimony, Mr. Hill applied a DCF analysis to one sample of eleven electric utilities and, in addition, performed a multi-stage DCF analysis that selects particular growth rates for an initial growth and final stage long-term growth rate. See DOD T-2 at 20-32.

Mr. Hill based the expected dividend yield component of his DCF analysis on a six-week average stock price. For the growth component, Mr. Hill examined a broad array of growth rate estimates, including (1) historical and forecast sustainable growth rates, (2) historical growth rates in book value, earnings, and dividends, (3) Value Line growth forecasts, and (4) the consensus growth forecasts reported in Zacks and IBES. See HECO RT-19 at 12.

For Mr. Hill's electric utility sample group, Mr. Hill's direct testimony DCF ROE result was 10.01%, and his multi-stage DCF ROE was 9.62%. See DOD T-2 at 44. In rebuttal, Dr. Morin identified a number of problems with Mr. Hill's application of the DCF model as used in Mr. Hill's testimony.

First, it is unclear how Mr. Hill derived his five-year average sustainable growth rate of 5.2% for American Electric Power ("AEP"), which utility Mr. Hill selected as a "case study" to derive his DCF growth forecast. In addition, as discussed in connection with Mr. Parcell's testimony above, the sustainable growth method should be given little, in any weight in this proceeding. See HECO RT-19 at 12-16. Moreover, the Value Line estimates of ROE and retention ratio on which Mr. Hill relies are not necessarily representative of the market consensus, and run the risk that such forecasts are not representative of investors' consensus forecast. Further, contrary to common regulatory practice, the forecasts of the expected ROE published by Value Line are based on end-of-period book equity rather than on average book equity. This one error alone understates Mr. Hill's DCF estimates by approximately 10-20 basis points, depending on the magnitude of the book value growth rate forecast. See HECO T-19 at 16-17; response to DOD-RIR-40.

Second, as discussed in connection with Mr. Parcell's testimony above, historical growth rates have little relevance as proxies for long-term growth forecasts and are largely redundant. See HECO RT-19 at 17-18.

Third, Mr. Hill's reliance on Value Line dividend growth forecasts (1) runs the risk that such forecasts are not representative of investors' consensus forecast, and (2) is inappropriate at this time, as the Value Line dividend growth forecasts are largely dominated by the anticipated dividend performance over the next few years and higher business risk. Reliance on "near-term" dividend growth is improper because it is expected that energy utilities will continue to lower their dividend payout ratios over the next several years in response to increased business risk. Moreover, in the current environment where utilities, including Hawaiian Electric, are increasing their capital expenditures, dividends cannot be expected to grow at the same rate that investors expect earnings to grow. Further, given the paucity and variability of dividend forecasts, use of dividend forecasts produces unreliable DCF results. See HECO RT-19 at 18-20.

Fourth, with respect to Mr. Hill's multi-stage DCF analysis, Mr. Hill inappropriately based his second stage growth rate on the Congressional Budget Office's long-term 2009-2019 GDP growth forecast of 4.2% for the U.S. economy. This forecast is inconsistent with the long-term historical growth of the economy of 6.94% that Mr. Hill calculated on in DOD-205. In addition, Mr. Hill's comparison to a short-term growth rate forecast (the next ten years) is inappropriate because the growth term of the DCF model is perpetual in nature. In short, Mr. Hill's second-stage growth forecast of 4.2% for his comparable group of electric utilities slightly understated the long-term expected GDP nominal growth by approximately 90 basis points. See HECO RT-19 at 22-23, 53, 59; response to CA-RIR-26.

Fifth, the "checks" employed by Mr. Hill on his DCF analysis are improperly disguised versions of the DCF methodology. For example, the Modified Earnings-Price Ratio methodology collapses into the constant DCF model in all but two very limited circumstances (not present for Hawaiian Electric) see HECO RT-19 at 23-25, and, as admitted by Mr. Hill, the

M/B ratio methodology is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method. See HECO RT-19 at 25.

4. Need for Flotation Cost Adjustment

Dr. Morin's market-derived estimates of Hawaiian Electric's cost of common equity have been adjusted upward by 30 basis points to account for flotation costs in order to provide investors with the opportunity to earn a fair return on their investments.

In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. Flotation costs have both (1) a direct component representing the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.), and (2) an indirect component representing the downward pressure on the stock price as a result of the increased supply of stock from the new issue. HECO RT-19 at 47.

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. It is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital. This in turn amounts to an adjustment of approximately 30 basis points, depending on the magnitude of the dividend yield component. The flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years. See HECO RT-19 at 47-51; HECO-1909.

In his written testimony, Mr. Parcell argues that "[t]here is no need to make a flotation adjustment" on the grounds that Hawaiian Electric "has made no demonstration that the Company has incurred any issuance costs". In addition, Mr. Parcell contends that "[t]o make a market-to-book adjustment for companies whose market-to-book ratio already exceeds 125 percent is unnecessary and inappropriate, since any common stock issuance would actually increase the book value of existing stockholders' stock." CA-T-4 at 64. Mr. Hill raises similar arguments for the exclusion of a flotation cost adjustment. See DOD T-2 at 45-47. Dr. Morin's responses to these arguments are set forth on pages 27-32 of HECO RT-19. See also response to DOD-RIR-52.

Nevertheless, the Commission has previously recognized issuance costs and provided for an allowance for such issuance costs. In other instances, the Commission has simply considered issuance costs, along with risk differences, in arriving at its final judgment as to cost of equity. See Docket No. 7766 (Hawaiian Electric's 1995 test year rate case), Decision and Order No. 14412 (December 11, 1995) at 98-99.

D. HAWAIIAN ELECTRIC'S INVESTMENT RISK

The rate of return must take into account the investment risk of the Company. The investment risk of a firm includes its business risk and financial risk.

Business risk refers to all risks that affect the relationship between revenues and expenses of a company excluding the effect of using debt to finance the assets of a company. An increase in business risk will depress the value of the security.

Financial risk reflects the risk of using debt to finance assets and its impact on the balance between revenues and costs. Interest, unlike dividends, must be paid even during adverse circumstances. As a result, when revenues decrease relative to costs, a leveraged company will incur a greater reduction in income than a non-leveraged company. Further, debt can expose companies to the risk of bankruptcy. An increase in financial leverage, or debt, and a resulting lower common equity ratio, will increase financial risk, and depress the price of the security.[49]

1. Hawaiian Electric's Business Risks

The Commission has recognized a number of factors in prior rate case decisions for the Hawaiian Electric Companies that adversely impact their business risk. They include: (1) Hawaiian Electric's service territory is geographically isolated; (2) Hawaiian Electric lacks interties, which precludes the Company from having other utility systems provide reliable backup generation sources; (3) there is a scarcity of generation sites in Hawaiian Electric's service territory, (4) Hawaiian Electric purchases a substantial percentage of its power through firm capacity contracts, which impacts Hawaiian Electric's financial condition; (5) Hawaiian Electric's service territory is significantly dependent upon tourism; (6) there has been a need for frequent rate adjustments; (7) Hawaiian Electric is significantly dependent on oil for electric generation; and (8) Hawaiian Electric is a relatively small electric utility company. The Commission has also recognized the relative size of the Companies' capital budgets as a differentiating factor.

In her direct testimony, Ms. Sekimura addressed the business risk considerations analyzed by the credit rating agencies, focusing on the S&P considerations, since they are the

[49] It is important to note that published debt/equity ratios generally do not account for the impact of the "debt equivalency" of firm purchased power obligations. Differences in firm purchased power obligations can impact the relative financial risk of electric utilities.

most transparent. Business risk considerations cited by S&P[50] include five basic areas of analysis: regulation, markets, operations, competitiveness, and management. See HECO T-20 at 13. The Company faces several business risks underlying each of the five basic factors.[51]

a. Regulation

As further discussed in below, regulation is a critical aspect that underlies a utility's creditworthiness, and decisions by the regulators can profoundly affect financial performance. As a result, regulation has become a major factor – and to many investors, the single most important factor – in utility investment-related decision making.

Energy Cost Adjustment Clause

For many years the Company has been allowed the use of an ECAC. The ECAC allows Hawaiian Electric to automatically increase or decrease rates to reflect changes in the Company's costs of fuel and purchased energy above or below the expense levels included in base charges, without a rate proceeding.

Hawaiian Electric's investors view the Company's existing ECAC mechanism very favorably because it significantly reduces the risks associated with fluctuation in the price of imported fuel oil. In its credit assessment of Hawaiian Electric, S&P has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality, and in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality. HECO T-20 at 28.

In 2006, new legislation[52] required that the Commission evaluate the continued use of

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[50] HECO T-20 at 13, citing S&P article, "Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers" dated September 14, 2006 filed in Docket No. 2006-0386 (HECO 2007 TY rate case) as HECO-1908.

[51] See S&P article: Key Credit Factors: Business And Financial Risks In The Investor-Owned Utillities Industry, November 26, 2008, filed as Attachment 1 to the response to CA-RIR-41.

[52] Act 162, 2006 Haw. Sess. L., added a provision to HRS § 269-16 reiterating the Commission's discretion to evaluate any automatic fuel rate adjustment clause requested by a utility.

ECAC in each rate proceeding in which it was requested by the Company. The Company's investors are clearly concerned by the legislative action. In its credit assessment of Hawaiian Electric, dated May 23, 2008[53], S&P cited the existing ECAC as a major rating factor strength, but then further cited any potential change to the existing ECAC as a major rating factor weakness:

> (1) "The current ECAC design is under consideration by the Hawaii Public Utilities Commission ('PUC') in all three of HECO's pending utility rate cases; a material change to the ECAC could harm the company's financial condition." and
>
> (2) "Actions that weaken the ECAC's ability to protect utility credit quality would be of concern."

HECO T-20 at 13-14, 26-27.

There are other investor risks associated with fuel and purchased power, including: (1) the Company's significant power purchase obligations, which create debt-like obligations that are of concern to investors, and which may further impact investor views due to changes that have occurred in the accounting treatment of these obligations; (2) exposure to financial variability due to changes in fuel efficiency; and (3) risks of fluctuations in the carrying costs of fuel inventory.

In general, investors are not specifically compensated for the risks they take relating to fuel. Although dependence on imported fuel oil increases business risks, the existing ECAC mechanism significantly mitigates this risk. The risks associated with changes in the fuel inventory carrying costs are generally not significant from an investor's perspective and investors do earn a return on the fuel inventory included in rate base. HECO T-20 at 29-30.

Investor risks associated with purchased power are considered in establishing the appropriate rate of return on equity. In HECO T-19, Dr. Morin discusses the need for increased

[53] S&P Ratings Direct "Hawaiian Electric Co. Inc." dated May 23, 2008 filed as HECO-2008.

shareholder compensation resulting from purchased power. HECO T-20 at 30.

Regulatory Action

As discussed below, the Company has numerous regulatory actions pending before the Commission that will impact the credit rating agencies' assessment of Hawaiian Electric's regulatory risk. Regulatory decisions that suggest the utility will not have regulatory support increase the Company's risk profile, and thus place into jeopardy Hawaiian Electric's current credit ratings. A downgrade of those ratings would increase the Company's cost of capital, and thus, ultimately, the rates that customers are required to pay. HECO T-20 at 14.

Renewables

Federal and State policies, enacted and currently under consideration, mandate higher use of renewable resources. The Renewable Portfolio Standards ("RPS") law, as amended by the Legislature in 2004, in 2006 and in 2009, requires Hawaiian Electric (in aggregate with HELCO and MECO) to obtain certain percentages of sales from renewable electrical energy resources ("REs").

In 2009, the Legislature passed H.B. No. 1464, H.D. 3, S.D. 2, C.D. 1, which was enacted as Act 155, and effectuates the change in the RPS law. Act 155 substantially increases the electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS must be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements.[54]

[54] In addition to increasing Hawaiian Electric's RPS requirements, Act 155 directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies." In particular, the legislation would require that the energy efficiency portfolio standards ("EEPS") be designed to achieve 4,300 GWh of electricity use reductions statewide by

S&P's assessment of the impact of RPS on the industry is:

> Largely through legislation, the political process has engineered RPS, but it is the utilities that will ultimately be responsible for implementing the standards. We question whether state legislatures, or citizens (in the case of Colorado or Washington, where voter mandates initiated RPS), understand the full cost impact of the RPS programs on customer bills over the next 20 years. An equally important credit concern is the extent that utilities will be held responsible if unforeseen events prevent them from reaching targets. The willingness of regulatory commissions to adopt flexible compliance guidelines that exempt utilities from penalties if unexpected delays occur in meeting interim or final targets can mitigate this concern. And many states do have "off-ramps" that allow utilities to ratchet back RPS if they prove to be uneconomic.[55]

In July 2007, Act 234 of the 2007 Hawaii State Legislature became law and requires a statewide reduction of greenhouse gas ("GHG") emissions by January, 1, 2020 to levels at or below the statewide GHG emission levels in 1990. Because the regulations implementing Act 234 have not yet been promulgated, the Company cannot predict the impact of Act 234. HECO T-20 at 19.

S&P has this current industry-wide assessment of potential GHG emission limitations impact on credit quality:

> In short, Standard & Poor's Ratings Services believes climate change-related costs will have a minimal overall effect on electric utility ratings if policymakers attempt to accomplish greenhouse gas reductions as efficiently as possible over a time span that allows rates to absorb those costs on a politically palatable schedule. To put it in the negative, credit quality will suffer if legislatures impose CO2 limits in such a way as to disrupt resource planning by utilities, overwhelm the necessary technological advances, and require rate increases at a time when ratepayers are already suffering from rising market and commodity prices.[56]

The Energy Agreement and Act 155 present new and increased risks to the Company. HECO RT-20 at 10. The Energy Agreement commits Hawaiian Electric to facilitate the integration of substantial amounts of clean, renewable energy into its grid and to enable

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2030, with interim Commission-established goals for 2015, 2020, and 2025.

[55] HECO T-20 at 18, quoting S&P Ratings Direct "The Race for the Green: How Renewable Portfolio Standards Could Affect U.S. Utility Credit Quality" dated March 10, 2008 filed as HECO-2011.

[56] HECO T-20 at 19, quoting S&P Ratings Direct "The Credit Cost Of Going Green For U.S. Electric Utilities" dated March 7, 2008 filed as HECO-2012.

electricity consumers to manage their electricity use more effectively. Uncertainty relating to the requirements for and technology of capital expenditures relating to these commitments increases business risk, in addition to the financing and cost recovery risks which increase financial risk. Response to DOD-IR-43.

For example, under the new feed-in tariff, the Hawaiian Electric Companies will be required to purchase certain types of energy under certain conditions at a rate established by the Commission. The impact on the Company of this new obligation will depend on many factors, including the impact on the operations of the Company, the magnitude of the obligation, and the conditions under which the Company must make payments. An adverse impact on the Company's operations may reduce reliability and negatively impact business risk which would adversely impact credit quality.

As discussed below, large obligations will result in larger amounts of imputed debt, which will negatively impact the Company's financial ratios as viewed by credit rating agencies and negatively impact credit quality. A tariff which requires the Company to make payments regardless of whether the energy is delivered could result in capital lease obligations being recorded on the Company's financial statements. Capital lease obligations result in additional debt, and thereby negatively impact the Company's financial ratios and credit quality. HECO RT-20 at 16.

b. Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which the Company operates.

Economy

The Company's operating results are influenced by the volatility of the national and state economy and their impact on the economy of the island of Oahu. Tourism, the largest component of Hawaii's economy, can fluctuate significantly as a result of terrorist acts across the globe, the geopolitical and war situation, and national and international economic conditions. In addition, a large portion of the Company's revenues comes from the large military presence in the state. The impact of having such a large single customer sector is that it potentially creates volatility in the Company's revenues resulting from the nation's decisions with respect to military bases and deployment. HECO T-20 at 20.

Recent airline closures, high travel costs, and national economic uncertainty all play into uncertainty in Hawaii's economy. In its credit assessment of Hawaiian Electric, dated May 23, 2008[57], S&P stated that "recent revisions to the state's economic indicators show a distinct slowdown. Lower economic activity will reduce electric sales and revenues, all else equal."

DSM Programs

The Company recognizes the need for and benefit to Hawaii of reducing Hawaii's dependence on fuel oil and central station generation to meet the electricity needs of its customers. Since 1996, Hawaiian Electric has implemented energy efficiency demand-side management ("DSM") programs, which have provided incentives to its customers to implement measures that reduce the use of electricity or use electricity more efficiently. Companies incur risks when they encourage customers to reduce the use of their product, which is the case for Hawaiian Electric where DSM Programs are designed to influence the utility customer's uses of energy to produce desired changes in demand. HECO T-20 at 20-21.

Although Hawaiian Electric's energy efficiency programs were transferred to a third-

[57] S&P Ratings Direct "Hawaiian Electric Co. Inc." dated May 23, 2008 filed as HECO-2008.

party Public Benefits Fund Administrator in 2009, the impact of reduced electricity consumption associated with DSM programs (regardless of who administers them) represents an ongoing business risk for Hawaiian Electric.

Sales Growth

Hawaiian Electric demonstrated that the cumulative effect of these factors has resulted in a trend of decreasing sales since 2004[58] and recorded September 2009 year-to-date energy sales 3.5% less than recorded year-to-date energy sales of a year earlier and 1.6% less than the year-to-date energy sales forecasted for the 2009 test year.[59]

As a result, as further discussed below, all three Companies' ROEs were more than 300 basis points below that of their authorized ROEs.[60]

c. **Operations**

When assessing a utility's operations, creditors focus on the Company's ability to provide reliable and safe electric service, the cost to achieve those goals, and the ability to recover those investments.

Capital Investments

The Company is projecting a need for new utility infrastructure to improve reliability and to support growth. Construction of generation and transmission facilities will face many challenges due to public sentiment, politics, and permitting requirements. The processes to get all the approvals needed to install these capital additions take many years and therefore put investor funds at risk for extended periods. HECO T-20 at 22.

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[58] HECO-212, Docket No. 2008-0083, page 1, filed July 3, 2008; see HECO Hearing Exhibit 1, Docket No. 2008-0083, HECO T-2, page 2, filed October 28, 2009.

[59] HECO Hearing Exhibit 3, Docket No. 2008-0083, HECO T-2, page 2, re-filed (on a confidential basis) November 3, 2009.

[60] As of August 3, 2009, the ROE found by the Commission to be reasonable in the most recent final rate decision for each utility was 10.7% for Hawaiian Electric (Docket No. 04-0113), 11.5% for HELCO (Docket No. 99-0207), and 10.94% for MECO (Docket No. 97-0346).

Further, the Company needs to support an increase in the base level of capital expenditures, as well as capital expenditures growing beyond traditional requirements, in order to support renewable investments and customer options. Although the Commission's prior approval of construction projects (see Ms. Nagata's discussion in HECO T-17 regarding General Order No. 7) helps to reduce the Company's business risk, it does not eliminate it completely. There have been cases where the Company has had to make a substantial commitment of funds prior to Commission approval under paragraph 2.3.(g)(2) of General Order No. 7 in order to maintain the schedule for a project essential to reliable service. Construction projects may encounter circumstances, which were unforeseen at the time the project was approved, that increase the cost of the project. When these types of cost increases are challenged in later cost recovery proceedings, the utility must re-defend its decision to proceed with the project in a backward looking review process benefited by hindsight. HECO T-20 at 23.

Being an island environment, Hawaii has no inter-ties to other sources of electricity and must build its own resources to meet its needs. This increases the significance of making investments in capacity and reliability, and underscores the importance of maintaining access to capital markets to be able to tap the financial resources when needed for such capital investment. The Company must be able to construct the facilities and to finance them in order to continue to provide reliable electric service. HECO T-20 at 23.

S&P has addressed electric utilities' rising capital expenditures in many of its reports. For example, in a report dated March 9, 2009, S&P cautioned that, "Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs." The report added that: "In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle", and "[t]o the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures." HECO RT-20 at 23.

Purchased Power

The Company expects to purchase approximately 42% of its energy from independent power producers ("IPPs").[61] Power purchase agreements ("PPAs") have been entered into based on the Company's obligations under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and state laws and rules encouraging the purchase of power from non-fossil fuel producers and qualifying facilities under PURPA, and are filed with the Commission for its review and approval. The contracts are obligations that generally must be paid before investors receive any compensation for the use of their funds. Hawaiian Electric's investors receive no compensation for the PPAs, but have earnings potential at risk if power purchase costs are not fully recovered in rates (through base rates or the ECAC). HECO T-20 at 23-24.

Rating agencies are well aware of the Company's large purchased power obligations. S&P states in its November 28, 2008 Summary report:[62]

> The consolidated financial profile is 'aggressive', reflecting in part the very heavy debt imputation Standard & Poor's Ratings Services applies to HECO for its long-term power purchase agreements (PPAs). These obligations added about $469 million in on-balance-sheet debt 2007 and about $568 million beginning in March 2008 and reflect evergreening of PPA obligations. (Consistent with our published criteria, we assume that expiring PPA contracts are replaced with new ones at similar terms.) While we apply significant debt obligations to HECO, we also

[61] See HECO-402.
[62] HECO RT-20 at 18-19.

recognize the historical reasons that have led to HECO buying a substantial amount of its power supply from third-party suppliers and that the regulatory recovery of capacity costs associated with these contracts has been supportive.

Compliance with Environmental Laws and Regulations

In general, the electric industry faces increasingly stringent environmental laws and regulations which regulate the operation and modification of existing facilities, the construction and operation of new facilities, and the proper cleanup and disposal of hazardous waste and toxic substances. The Company is at risk for the direct cost of compliance as well as the economic consequences of any impact on operations. HECO T-20 at 24.

Competitive Bidding

On December 8, 2006, the Commission issued Decision and Order No. 23121 in Docket No. 03-0372, which included a framework to govern competitive bidding. Competitive bidding may result in additional power purchase contracts. which would increase the financial risks to the Company either through the recognition as actual debt (i.e., a lease or consolidation) or as imputed debt HECO T-20 at 24.

Because competitive bidding for new generation in Hawaii is a new process, it creates uncertainty. The competitive bidding framework provides high-level guidance to the process, however details in execution can significantly impact the planning to meet system needs, reliability, and cost recovery of parallel efforts. There are many special considerations in evaluating bids that arise from the fact that Oahu is an island that cannot import power. In a competitive bidding environment, Hawaiian Electric must assess the performance risks associated with each bid. Contractual remedies for non-performance need to go beyond financial consequences, and need to result in the supply of electricity when it is needed. Further, the utility will undertake parallel efforts to assure a back-up plan. If the parallel plan is terminated too early, the end result may be a generation shortfall. If the parallel plan is pursued too long, costs may be incurred which may be viewed as unnecessary in a backward looking review process benefited by hindsight. HECO T-20 at 25.

d. Competitiveness

Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnection to other electric utilities, Hawaiian Electric faces competition from IPPs and customer self-generation, with or without cogeneration. HECO T-20 at 25.

Rising Prices

Fuel oil prices continue to fluctuate, resulting in fluctuating electricity costs. Increasing fuel oil prices result in renewable energy sources being relatively economical. High fuel oil prices and high-cost renewable energy result in higher electricity costs. Higher costs of electricity drive customers to find means of reducing their energy costs, through energy conservation or through alternative energy sources. HECO T-20 at 25-26.

Bypass Risk – Distributed Generation, Self-Generation

Customers today have more access to alternative energy sources (i.e., self-generation, distributed generation, photovoltaic installations), which are causes for concern for the Company. As these technologies become more economically attractive for customers, customers may reduce their reliance on, and in some cases may disconnect from, the system, which could put the Company at risk of lost revenues and possible stranded assets. HECO T-20 at 26.

e. Management

Evaluating management is of paramount importance to the credit rating agencies' analysis, because management decisions affect all areas of a company's operations and financial health. HECO T-20 at 26.

Commitment to Credit Quality

The Company recognizes that rating agencies' and investors' assessment of management has an impact on the Company's credit rating. Thus, management is committed to maintaining credit quality and strives to keep the financial community abreast of the Company's goals, objectives, and strategies at its meetings with the rating agencies. HECO T-20 at 26.

f. Summary of Business Risks

Hawaiian Electric's business risks impact its capital structure. Increased business risks have increased the pressure to reduce financial risk in order to maintain the Company's credit rating. Since the Company cannot control much of the business risk it faces, it must be resolute in controlling its financial risk. The primary means of reducing its financial risk is by increasing or, at minimum, maintaining the proportion of equity in its capital structure. HECO T-20 at 44.

2. Hawaiian Electric's Financial Risk

Financial risk stems from the method used by a firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt capital. Although the use of fixed cost capital (debt and preferred stock) can offer financial advantages through the possibility of leverage of earnings, it creates additional risk due to the fixed contractual obligations associated with such capital. Debt carries fixed charge burdens which must be supported by the company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges in relation to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk. HECO T-19 at 52-53.

Variations in operating earnings cause amplified variations in equity returns when debt financing is used. The spread in equity returns is wider in the case of debt financing, and the greater the leverage, the greater the spread and the greater the cost of common equity. HECO T-19 at 53. Financial risk considerations taken into account by credit rating agencies include financial characteristics, financial policy, profitability, capital structure, cash flow protection and financial flexibility, as reflected in a firm's financial ratios. See HECO T-20 at 45.

a. Imputed Debt for PPAs and Operating Leases

Companies that have more debt (less equity) are deemed to have higher financial risk than companies that have less debt (more equity). S&P has indicated that it makes adjustments to debt amounts reported on the Company's financial statements in two areas.[63] Certain obligations of the Company that are not reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." In Hawaiian Electric's case, the credit rating agencies impute debt for its PPAs and long-term operating lease obligations.

Hybrid securities and preferred stock have certain features that are equity-like and certain features that are debt-like. In calculating ratios, S&P treats hybrids as debt, but gives some equity credit for the hybrids. The equity aspects of the hybrids decline over time. Further, S&P generally accords some debt treatment to preferred stock, depending on the features of the issuance.

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[63] HECO T-20 at 48-49.

b. **Purchased Power**

Purchased power contracts affect an electric utility's financial risk profile.[64] An electric utility with long-term purchased power contracts possesses higher financial risks than a utility without such contracts, all else remaining constant. A company's obligations pursuant to long-term purchased power contracts are comparable to long-term debt and are treated as such by investors and bond rating agencies. The same is true for leveraged lease arrangements. HECO T-19 at 53.

In an article published in Standard and Poor's The Global Sector Review, dated May 8, 2003, S&P updated its criteria for capital structure treatment of purchased power agreements ("PPA"), noting that industry changes warranted "recognition of a higher debt equivalent when capitalizing PPAs." S&P explained that this more stringent treatment would be factored into its current policy of adjusting the debt/equity ratio of a company for debt equivalents:

> The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Non-capitalized leases, debt guarantees, receivables financing and purchased power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios.

The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's purchased power contract obligations are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk. HECO T-19 at 54.

As indicated by Dr. Morin, financial theory provides a reasonable and consistent method of adjusting for the increased risk and return associated with purchased power contracts.[65]

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[64] HECO T-19 at 53-54.
[65] HECO T-19 at 54-55.

c. **Imputed Debt Due to PPAs**

The Company's power purchase agreements currently increase the Company's risk profile as a result of the imputed debt treatment of the PPAs. The impact of PPAs on the Company's risk profile could be increased in the future if the PPAs:

(1) are treated as capital lease obligations reflected as debt on HECO's financial statements, or

(2) the sellers are consolidated (including the seller's debt) on HECO's financial statements as a result of FIN46R.

See HECO T-20 at 33-44.

"Imputed debt" (also referred to as "implied debt") refers to adjustments to the debt amounts reported on financial statements prepared under generally accepted accounting standards. Certain obligations do not meet the GAAP criteria of "debt", but have debt-like characteristics; therefore, credit rating agencies "impute debt and interest" in evaluating the financial ratios of a company. HECO T-20 at 34.

S&P calculates the imputed debt for PPAs by taking the present value of the total fixed payments over the life of the contracts, using the company's average cost of debt as the discount rate (6%) for the present value calculation.[66] It then determines a risk factor to apply to the contract to reflect the riskiness to the utility based on the terms of the contract and assurances of cost recovery. In its credit assessment of Hawaiian Electric, dated May 23, 2008,[67] S&P assigned a risk factor of 50% to the Company's firm capacity power purchase contracts. The

[66] Other credit rating agencies also consider the impacts of power purchase obligations; however, the Company utilizes the S&P methodology because S&P is most transparent on methodology they employ. S&P published its original PPA criteria in 1991, and provided updates in 1993, 2003 and 2007. S&P "Buy versus Build: Debt Aspects of Purchased-Power Agreements" dated May 8, 2003 was filed as HECO-2111 in Docket No. 04-0113, S&P "Request for Comments: Imputing Debt to Purchased Power Obligations" dated November 1, 2006 was filed as HECO-1915 in Docket No. 2006-0386, and S&P Ratings Direct "Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements" dated May 7, 2007 filed in response to DOD-IR-68 in Docket No. 2006-0386. HECO T-20 at 34 n.26.

[67] See S&P Ratings Direct "Hawaiian Electric Co. Inc." dated May 23, 2008 filed as HECO-2008.

risk factor is applied to the present value of the fixed payments under the contract to calculate the imputed debt:[68]

Risk Factor x Present Value of Fixed Contract Payments = Imputed Debt

In addition, in 2007, S&P revised its methodology of calculating imputed debt to include "evergreen treatment" and "all-in energy pricing" of power purchase agreements. Under "evergreen treatment", contracts expiring within 12 years are effectively assumed be renewed such that all PPAs have a minimum 12 year term for purposes of the imputed debt calculation. The actual fixed payment terms are applied to the existing contract, then a proxy peaker unit capacity payment is applied to the unit capacity to calculate the estimated fixed payments for the period beyond the existing contract term to the 12 year minimum term. HECO T-20 at 34-35.

For power purchase contracts that have pricing based on a single, "all-in price" (such as the wind PPAs at HELCO and MECO), S&P applies a proxy peaking capacity rate to the capacity of the facility, adjusted for the estimated capacity factor (i.e., the expected output/output capacity). HECO T-20 at 35.

In direct, the imputed debt for Hawaiian Electric's PPAs increased its December 31, 2009 total debt to total capitalization ratio from 44%, unadjusted for purchased power contracts, to 56%, a substantial increase that raises the Company's financial risk. HECO T-19 at 56; HECO T-20 at 49 and nn. 45-46; HECO-WP-2016 at 5, 10; HECO-2016.

In response to DOD-IR-31, Dr. Morin presented a table compiled from Value Line Investment Survey data showing that the Hawaiian Electric Companies' percentage of generation from purchased power of 39% far exceeds the average of 15% for traditional vertically-

[68] HECO T-20 at 34.

integrated electric utilities in Dr. Morin's sample group of electric utilities, at least for those companies that reported such information in Value Line.. Dr. Morin also noted that the financial risk due to the presence of off-balance sheet liabilities such as purchased power contracts is already reflected in traditional measures of risk for the Hawaiian Electric Companies and for Dr. Morin's comparable-risk companies, such as beta and bond rating.

This negative impact on Hawaiian Electric's total debt to total capitalization ratio could be mitigated to a degree if greater assurance of cost recovery of all purchased power costs reduces the risk factor that the rating agencies apply to Hawaiian Electric's power purchase contracts.

3. Financial Risk Analyses

a. Financial Ratios

To assess the financial risk of a company, credit rating agencies examine a number of measures, including the following:[69]

(1) Funds from operations/total debt – measure of ability to pay total debt from operational revenues.

(2) Funds from operations/interest coverage – measure of ability to pay interest from operational revenues.

(3) Total debt to total capital – measure of the financial leverage used by the company.

S&P uses these financial ratios, along with qualitative analyses, to determine a financial risk profile.[70] The financial risk profile evaluated in combination with the business risk profile is indicative of a given rating.[71] Further, S&P is quick to note that the ratings indicated by the assigned business and financial risk profiles are evaluated in conjunction with other qualitative

[69] HECO T-20 at 45. Discussion is focused on ratios as calculated by S&P because they are more transparent as to how they calculate the ratios and how the ratios impact credit ratings.

[70] HECO T-20 at 45.

[71] HECO T-20 at 45-46.

factors in determining its credit rating.[72]

At the time the instant Application was filed in July 2008, S&P classified HECO as "strong" business risk and "aggressive" financial risk.[73] This profile indicates an implied rating of BBB- based on the table above, representing a midpoint for a utility with those designations, the full range being BBB, BBB-, and BB+. However, S&P has other considerations in their credit rating analysis and has assigned Hawaiian Electric a corporate credit rating at the top of that range at BBB (one notch higher than BBB-). A graphic presentation of the ratings scale is presented in HECO-2016. HECO T-20 at 46.

In direct, Hawaiian Electric's theoretical ratios based on the test year projections were provided on HECO-2016. A comparison of the Company's theoretical ratios to the financial guidelines applicable to Hawaiian Electric for the 2009 test year was shown on HECO-2016. Without rate relief (at current rates), Hawaiian Electric's credit ratings with its business profile of "strong" would line up as follows within S&P's financial risk parameters:

- The funds from operations/total debt ratio of 12% is indicative of a BB+ rating;
- The funds from operations/interest coverage ratio of 3.0x is indicative of a rating on the borderline between BBB and BBB-;
- The total debt/total capital ratio of 56% is indicative of a rating of BB+.

In general, without rate relief, S&P's financial guidelines would point to a BBB- credit rating for the Company, one notch below its current corporate credit rating.

With rate relief (with the CIP1 Generating Unit step increase):

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[72] HECO T-20 at 46, citing S&P Ratings Direct "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix" dated November 30, 2007 filed as HECO-2014.

[73] S&P Ratings Direct "U.S. Regulated Electric Utilities, Strongest to Weakest" dated June 2, 2008 filed as HECO-2015. Hawaiian Electric's "strong" business risk profile does not imply that its business risk is stronger, weaker, or identical to the industry average because the "strong" designation applies to very few utilities; the "excellent" designation characterizes most utilities. HECO RT-19 at 32.

- The funds from operations/total debt ratio of 17% would be indicative of a BBB- rating;
- The funds from operations/interest coverage ratio of 3.9x would be indicative of a BBB+ rating;
- No change to the total debt/total capital ratio of 56% would be indicative of a BB+ rating.

A "strong" business risk profile with these theoretical financial ratios would likely be at the BBB rating level, consistent with Hawaiian Electric's current rating status. Because the total debt/total capital ratio is not directly impacted by rate relief, it does not change and continues to be a drag on the Company's credit profile. Improvement in this ratio could result from a reduction in imputed debt, as discussed above.

The funds from operations/total debt and funds from operations interest coverage ratios show clear improvement resulting from rate relief. Rate relief is necessary to at least support the Company's current BBB credit rating. S&P's financial evaluation will be based on the Company's actual financial results; therefore, timely rate relief and mechanisms which align cost recovery with cost incurrence will improve the Company's potential to realize actual financial results consistent with what is allowed in this rate case. HECO T-20 at 46-48.

The projected financial ratios for the test year were updated in HECO-R-2007. There are two sets of ratios:

(1) Hawaiian Electric receiving rate relief and earning 11.0% return on common equity, and

(2) No rate relief.

Assuming an 11.0 % return on common equity, there were no significant changes to the financial ratios presented in direct testimony as a result of the revisions made to the various components of the cost of capital. Based on a current S&P business profile of "strong", the ratios were analyzed as follows:[74]

Without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.1 in BBB range of 3.0-3.5)

- the funds operations/total debt ratio is indicative of a BB+ rating (12% in BB+ range of 10-16.67%)

- the total debt/total capital ratio is indicative of a BB+ rating (56% in BB+ range of 55-60%).

With rate relief and 25% risk factor for purchased power:

- the funds from operations/interest coverage ratio is indicative of a A+ rating (4.6 in A+ range exceeding 4.5)

- the funds from operations/total debt ratio is indicative of an BBB- rating (21% in BBB- range of 16.67-23.33%)

- the total debt/total capital ratio is indicative of a BBB rating (50% in BBB range of 45-50%).

S&P indicates that Hawaiian Electric's financial ratios are weak for the Company's BBB credit rating. In its November 26, 2008 Summary, S&P stated:[75]

> The stable outlook reflects our expectation that, for now, HECO appears to have reasonable but not certain prospects for maintaining its existing financial profile, which is weak for the rating. Multiple near-term challenges face the company and include the uncertainties of the cost and feasibility impacts of the CEI, the potential for a significant reduction in electric sales in 2009 (due to economic contraction, energy efficiency initiatives, and customer response to high prices), and a recent softening in leading economic indicators. These challenges suggest that a negative outlook or downward revision to the ratings could be possible over the outlook horizon, as further weakening in the financial profile will not support ratings, and near-term business risk will be elevated until the particulars of the CEI are in place and prove to be supportive. Consistent, timely rate relief will continue to be key, and could offset or mitigate the effects of a declining economic environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

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[74] HECO RT-20 at 6-7.
[75] HECO RT-20 at 7-8.

In discussions in May 2009, S&P reiterated that Hawaiian Electric's financial credit metrics would not support the Company's current BBB rating and S&P would need to get more comfortable with the Company's financial metrics. In effect, Hawaiian Electric's financial credit metrics without improvement from rate relief, the Revenue Balancing Account, the Revenue Adjustment Mechanism, and the purchased power adjustment clause would not support the Company's current BBB rating. HECO RT-20 at 8.

As noted below, S&P's recent Research Update for Hawaiian Electric, dated May 27, 2009, revised the Company's outlook to negative (from stable), noting that the Company's credit metrics are only marginally supportive of the current BBB credit rating. HECO T-20 at 5-6; see HECO-S-2001.

b. Adjustment to Account for Risk Differential

In prior Decisions and Orders, the Commission has recognized that Hawaiian Electric (and its sister utilities) had greater risks than proxy groups of "comparable companies". Taking various risk factors into consideration, the Commission determined that an adjustment, based on judgment, was necessary to allow for these greater risks as compared to the comparable companies. The amount of that adjustment has varied at different points in time.

In MECO's 1992-1993 test year rate case, the Commission agreed "that MECO's business risk is higher than the business risk of the comparables used by both MECO and the Consumer Advocate", and made an upward adjustment of 115 basis points to allow for MECO's higher investment risk. The Commission found that "factors that make investing in MECO more risky than investing in other companies" include the lack of diversity in Maui's economy, the heavy reliance on imported oil as a fuel source, the lack of interconnections with reliable outside sources of power, the need for capital investments, the current national and local economic conditions, and MECO's minimal investment grade bond rating.[76]

In Hawaiian Electric's 1994 test year rate case, the Commission stated that "[w]e acknowledge the concerns of HECO about the ability of HECO to earn the allowed return under the Consumer Advocate's and DOD's calculated results. However, any deficiency in the Consumer Advocate's or DOD's analyses can be accounted for in our final determination of HECO's cost of common equity."[77] The Commission then found that an adjustment of 115 basis points was warranted (which took into account increasing interest rates, and Hawaiian Electric's minimal investment grade bond rating, as well as the Company's higher risks):[78]

> We also agree that HECO's business risk is higher than the business risks of the comparables used by all of the parties. The reliance on imported oil as fuel source, the lack of interconnection with reliable outside sources of power, and the need for capital investments are factors that make investment in HECO more risky than investments in other companies. In addition, the current national and local economic conditions and HECO's minimal investment grade bond rating are matters of concern. Taking all of these risk factors into consideration, we believe that an upward adjustment of 115 basis points to the 11.0 per cent cost of common equity derived above is appropriate. Such an adjustment is necessary to allow for HECO's business and financial risks. It also recognizes the effects of national and local economies and the currently increasing interest rates. By this adjustment the rate of return on common equity rises to 12.15 per cent.

In HELCO's 1996 test year rate case, the Commission again found that:

> We agree that HELCO's business risk is higher than both the HELCO Comparables and the CA Comparables. HELCO's substantial reliance on purchased power and the uncertainty regarding the extent to which that power will continue to be available, reliance on imported fuel, and need for capital investments are factors that make investment in HELCO more risky than investments in either group of comparable companies. To compensate for this higher risk and to account for the slight increase in long-term interest rates since the evidentiary hearing, we deem it appropriate to add 50 basis points to the result derived above, for a cost of common equity of 11.62 per cent, which we round to 11.65 per cent.[79]

[76] Docket No. 7000, Decision and Order No. 11668 (August 5, 1994) at 78-79.

[77] Docket No. 7700, Decision and Order No. 13704 (December 28, 1994) at 93.

[78] Id. at 94-95.

[79] Docket No. 94-0140, Decision and Order No. 15480 (April 2, 1997) at 67-68; see also Docket No.

The Commission rejected Mr. Parcell's view that no risk adjustment is appropriate in MECO's 1999 test year rate case:

> MECO strongly argues that risk adjustments are appropriate because it is riskier than the comparable companies. MECO points out that both its financial and business risk is higher than the comparables used by both parties. We agree. MECO's risk is inherent in its smaller size and is demonstrated by its higher operating ratio, lower quality of earnings, and weak level of internally generated funds for construction. In addition, the soft Hawaii economy and MECO's weak investment grade bond rating are matters which concern us.
>
> We find unpersuasive the Consumer Advocate's assertions that we need not make any risk adjustments. MECO is financially weaker and subsequently riskier than all of the proxy groups. Therefore, it is appropriate to make an adjustment for MECO's risk. Ultimately, both MECO and its customers benefit when MECO has sufficient financial integrity to attract capital. Accordingly, we believe that an upward adjustment of 50 basis points is warranted.[80]

In its Decision and Order in the 2000 test year rate case for HELCO, the Commission found:

> HELCO urges us to consider adjustments to account for its greater risk, relative to the comparable companies. We agree that a risk adjustment is appropriate. HELCO's risk is inherent in its smaller size and is demonstrated by its higher operating ratio, lower quality of earnings, and weak level of internally generated funds for construction. In addition, its substantial purchase power obligations and bond ratings are matters which concern us.
>
> We find unpersuasive the Consumer Advocate's assertions that we need not make any risk adjustments. HELCO is financially weaker and subsequently riskier than all of the proxy groups. Therefore, it is appropriate to make an adjustment for HELCO's risk. Ultimately, both HELCO and its customers benefit when HELCO has sufficient financial integrity to attract capital. Accordingly, we believe that an upward adjustment of 50 basis points is warranted. By this adjustment, the rate of return on common equity rises to 11.5 per cent.[81]

In his direct testimony, Dr. Morin indicated that a reasonable estimate of the risk differential is on the order of about 25 basis points, and adjusted his recommendation

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6432, Decision and Order No. 10993 (March 6, 1991) (HELCO) at 119; Docket No. 6999, Decision and Order No. 11893 (October 2, 1992) (HELCO) at 83-84; Docket No. 6998, Decision and Order No. 11699 (June 30, 1992) (HECO) at 159.

[80] Docket No. 97-0346, Decision and Order No. 16922 (April 1, 1999) at 49.

[81] Docket No. 99-0207, Decision and Order No. 18365 (February 8, 2001) at 75-76.

slightly upward to 11.25% in order to account for Hawaiian Electric's "slightly" higher relative risks, mainly due to its relatively small size and weaker-than-average effective capital structure engendered by the debt-like purchased power contracts, somewhat offset by my assumption of the continuation of the Company's current energy cost adjustment clause in the same manner as in the past. HECO T-19 at 52, 56-57; response to CA-IR-17.

Dr. Morin explained why Hawaiian Electric's small size must also be considered in arriving at the cost of common equity. Hawaiian Electric possesses small revenue and asset bases, both in absolute terms and relative to other utilities. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns. HECO T-19 at 56.

In rebuttal (and in his update), Dr. Morin did not adjust the cost of equity estimates to account for the fact that Hawaiian Electric's risk is higher than the industry average. Instead he stated that, "[s]hould the Commission allow the Company to establish and implement a revenue adjustment mechanism as proposed in the joint decoupling proposal filed by the Company and the Division of Consumer Advocacy in the decoupling proceeding (Docket No. 2008-0274), and given the various riders discussed earlier, the need for such a risk premium is unnecessary, and HECO's risk is comparable to the industry average." HECO RT-19 at 72-73; response to PUC-RIR-115.

E. IMPACT OF COST RECOVERY MECHANISMS ON ROE

1. Introduction

There was extensive discussion of the extent to which recently proposed cost recovery mechanisms would reduce the Company's business risk, and therefore reduce its required rate of return on common equity. The mechanisms include the REIP/CEI surcharge, the proposed Purchased Power Adjustment Clause ("PPAC"), and the proposed Decoupling Mechanism, which includes a proposed sales decoupling mechanism (to be implemented through a revenue balancing account or "RBA"), and a proposed revenue adjustment mechanism ("RAM").

In evaluating the impact of these mechanisms on the required ROE, a number of factors need to be taken into account:

(1) The Company's business risks have substantially increased as the result of the changes to the RPS Law, adopted as a result of the Hawaii Clean Energy Initiative ("HCEI"). The cost recovery mechanisms are intended to mitigate, to the extent practical, these <u>increased</u> risks.

(2) The market-derived cost of common equity for Hawaiian Electric is estimated by the experts from market information on the cost of common equity for other firms, including other electric utilities. Thus, if the market-derived cost of common equity for other firms already incorporates the results of these or similar mechanisms, then no further adjustment is appropriate or reasonable in determining the cost of common equity for Hawaiian Electric.[82]

[82] As Dr. Morin states in HECO RT-19, while adjustment clauses and cost tracking mechanisms are beneficial in mitigating operating risk, the approval of adjustment clauses and cost recovery mechanisms by regulatory commissions is widespread in the utility business and, in Hawaiian Electric's case, there are other significant factors to consider that work in the reverse direction for Hawaiian Electric. HECO RT-19 at 8.

(3) The effect of these proposed mechanisms on the cost of common equity for Hawaiian Electric is already accounted for, in substantial part, by eliminating the risk differential premium of 25-50 basis points previously incorporated in determining the cost of common equity for Hawaiian Electric relative to the cost of common equity for other electric utilities.

(4) The timing of the implementation of the proposed mechanisms must also be taken into account. None of the mechanisms were actually in place during the 2009 test year. This is particularly significant in the case of the proposed PPAC, which will not take effect until the Commission's final decision and order (if approved).

(5) Hawaiian Electric has been found to be riskier than the proxy electric utilities used to estimate the market-derived ROE for the Company. Without the risk mitigation measures, the differential in risk would be even greater due to the additional risks resulting from Act 155. Elimination of the risk differential in determining the ROE for Hawaiian Electric, as proposed by Dr. Morin, already accounts for much of the benefit of the new measures.

a. <u>Hawaiian Electric's Position</u>

Dr. Morin's original ROE recommendation of 11.25% was amended in rebuttal to a range of 11.00% - 11.25% assuming that the Company's proposed RDM is approved, and a range of 11.25% - 11.50% otherwise. HECO RT-19 at 68, 72-73.

In his update provided in HECO Hearing Exhibit 7, Dr. Morin concluded that a ROE in a range of 10.75% - 11.00% is reasonable. In view of the continuing turmoil and uncertainty in capital markets, and in view of the CAPM's understatement of capital costs under current crisis conditions, he noted that it would be appropriate to use the upper end of the range, absent the revenue decoupling mechanism ("RDM")/Rider mechanisms. The RDM would include the RBA and the RAM jointly proposed by Hawaiian Electric and the Consumer Advocate in the decoupling proceeding (Docket No. 2008-0274). The "Rider" mechanisms include the Purchased Power Adjustment Clause proposed in this proceeding and the Renewable Energy Infrastructure Program ("REIP")/Clean Energy Infrastructure ("CEI") Surcharge proposed in Docket No. 2007-0416. Tr. (Vol. VI) at 1,061. If the RDM/Rider mechanisms are approved by the Commission, the Company's risk is reduced, and the cost of common equity capital declines by some 25 basis points. Therefore, in that circumstance it would be reasonable to set the fair and reasonable ROE at the lower end of Dr. Morin's recommended range for ratemaking purposes, 10.75%. HECO Hearing Exhibit 7, filed November 2, 2009, at 1.

The 25 basis point adjustment is based on: (1) utility bond yield spread differentials between A-rated and Baa-rated bonds, (2) observed beta differentials, (3) differential common equity ratio requirements for S&P Business Risk Score, and (4) application of informed judgment. HECO Hearing Exhibit 7 at 2; see Tr. (Vol. VII) at 1122-34 (Morin).

Few if any other electric utilities face the risk factors and challenges faced by Hawaiian Electric, including: (i) the weakening of the regional economy, (ii) the Company's dependence on a huge capital spending program requiring external financing, (iii) weak financial metrics, (iv) uncertain feasibility and unknown costs of the Energy Agreement plans, and (v) regulatory risks, given that details of major provisions of the Energy Agreement have yet to be determined. See response to CA-RIR-16.

While Dr. Morin did not investigate every company in the comparable groups as to the presence of risk-mitigating mechanisms, the approval of adjustment clauses, ROE incentives riders, trackers, forward test years, and cost recovery mechanisms by regulatory commissions is widespread in the utility business. The extent of decoupling by state jurisdictions is shown on Attachment 1 of the response to CA-RIR-16. California electric utilities provide the most successful examples of the use of decoupling mechanisms. Dr. Morin notes that the currently allowed ROEs for California electric utilities are 11.5%, 11.35%, and 11.46% for Edison, PG&E, and Sempra, respectively. See response to CA-RIR-16.

In general, the presence of various risk-mitigating mechanisms (e.g., a sales decoupling mechanism and a revenue adjustment mechanism that reasonably mimics cost-of-service ratemaking; the REIP/CEI Surcharge; and the Power Purchase Adjustment Clause), all else remaining constant, should have a beneficial impact on the utility's required cost of common equity. However, it is difficult to quantify the exact impact of any given mechanism on the Company's return on common equity, since the impact should be considered along with other factors that impact the utility's business, such as (1) the dependence on third-party suppliers of renewable purchased energy, which could impact the utilities' achievement of their commitments under the Energy Agreement and/or the utilities' ability to deliver reliable service; (2) the impact of intermittent power to the electrical grid and reliability of service if appropriate supporting infrastructure is not installed or does not operate effectively; (3) the likelihood that the utilities may need to make substantial investments in related infrastructure, which could result in increased borrowings and, therefore, materially impact the financial condition and liquidity of the utilities; and (4) the commitment to support a variety of initiatives, which, if approved by the Commission, may have a material impact on the results of operations and financial condition of the utilities depending on their design and implementation. As such, financial and overall investment risks need to be considered in determining the "fair" rate of return on common equity used in a rate case to determine the utility's revenue requirements. See response to PUC-IR-174.

As explained in Hawaiian Electric's response to PUC-IR-115(c), total investment risk results from a multi-dimensional blend of several factors, including business risks, regulatory risks, financial risks, and size. The business risk component can in turn be disaggregated into sub-factors, including demand risk, concentration of demand, customer mix, and service territory economics. The regulatory risk component can also be disaggregated into broad sub-factors and individual specific ratemaking policies, such as the use or lack of use of normalized accounting, recovery of emission allowance costs, trackers, CWIP, rider mechanisms, fuel clauses, forward versus historical test years, and pre-approvals.

Although there is no quantification of the impact of the clauses on the Company's return on common equity, as discussed in HECO Hearing Exhibit 7, based on the results of all his analyses, the application of his professional judgment, the risk circumstances of Hawaiian Electric, and the unsettled current market environment, Dr. Morin proposes that a conservative just and reasonable return on the common equity capital of Hawaiian Electric's integrated electric utility operations lies in a range of 10.75% - 11.00%. Absent the RDM/Rider mechanisms, a ROE at the upper end of the range is reasonable under current capital market conditions and a ROE at the lower end of the range is reasonable assuming approval of the RDM/Rider mechanisms. Dr. Morin explains in HECO RT-19 that his recommended return on equity and the various risk-mitigating mechanisms, if adopted, might help to maintain the Company's existing credit ratings, all else remaining constant, through their favorable impact on regulatory risk investor perceptions, interest coverage ratios, and capitalization ratios.

b. <u>Other Parties' Positions</u>

The ROE witnesses for the Consumer Advocate and the DOD proposed reductions in the authorized ROE based on the availability of decoupling and other cost recovery mechanisms proposed in the Energy Agreement, but did not take into account the increased risk to which the utility is exposed that trigger the need for decoupling. The Consumer Advocate, especially, should have recognized these increased risks, as that was a significant reason for the inclusion of the cost recovery mechanisms in the agreement.

For the Consumer Advocate, Mr. Parcell argued that a steep downward ROE adjustment of 50 basis points is warranted to account for what he considers to be the risk-reducing effect of the RDM relative to the comparable companies. CA-T-4 at 54.

Dr. Morin disagreed with the magnitude of Mr. Parcell's downward risk adjustment on account of the RDM. Mr. Parcell's 50 basis point downward adjustment due to decoupling is arbitrary and overstated. HECO RT-19 at 54, 67-68. In addition, most, if not all, energy utilities in the industry are under some form of adjustment clause/cost recovery/rider mechanism(s). The approval of adjustment clauses, riders, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating and business risk scores. The experience with the operation of RDMs for electric utilities in general is very scant at this time, let alone the specific RDM variant that the Commission may adopt.

Aside from being arbitrary, it is apparent that Mr. Parcell's 50-basis point adjustment did not fully consider the regulatory, economic and financial challenges that the Company now faces, since they are not mentioned in his testimony. In particular, there is no discussion of the higher renewable portfolio standards established by Act 155. However, during cross-examination, Mr. Parcell accepted the statement that Hawaiian Electric has a renewable portfolio standard that is much more stringent than in other jurisdictions. Tr. (Vol. VI), page 1094.

Mr. Parcell's testimony on pages 65-66 of CA-T-4 further indicates his reluctance to consider the Company's challenges at the time he presented his 50-basis point reduction in CA-T-4. Mr. Parcell stated that to determine the authorized return on equity for the Hawaiian

Electric Companies, the Commission has in certain past cases added an adjustment of 50 basis points to the cost of equity for comparison companies based on the Company's higher business risks, current national and local economic conditions and HECO's minimal investment grade bond rating. However, he argued that this type of adjustment is no longer warranted, as during that time period, the Companies were experiencing downgrades. He also stated that the circumstances that HECO presently encounters, both from the regulatory and financial standpoints, are much improved in comparison to the situation in the 1990s when the Commission first made an upward adjustment to HECO's cost of equity.

However, during cross-examination, Mr. Parcell acknowledged that the process of downgrading has not stopped as S&P downgraded HECO's bond rating in May 2007 (primarily due, he stated, to the dramatic decline in the Hawaii economy), that according to his table on page 24 of CA-T-4 there are 38 electric utilities with S&P bond ratings above Hawaiian Electric's BBB rating, 11 with the same rating, and 11 below, that HECO was on negative outlook for a further possible downgrade and that the Company's credit metrics are only marginally supportive of the current BBB credit rating. Tr. (Vol. VI) at 1083-85, 1088. Mr. Parcell recognized that the Commission also considered the Companies' small size, remoteness and "may have" considered the substantial purchased power obligations (e.g., in the HELCO 2001 decision and order in Docket No. 99-0207) to support the upward ROE adjustments. Tr. (Vol. VI) at 1089.

Mr. Parcell agreed that to meet the RPS requirements, the Company will need to acquire more power purchase agreements which would result in more imputed debt on the Company's books.[83] Tr. (Vol. VI) at 1095. He also agreed, and that a 6.4% return on equity is not a good

[83] Mr. Parcell agreed that the developers of projects generally finance their projects based on the credit rating of the off-taker, which in this case would be Hawaiian Electric, that a downgrade would also

result if the authorized return is 10.7%. Tr. (Vol. VI) at 1095, 1099.

Mr. Parcell stated that in spite of the challenges, the proposed mechanisms would result in a "net gain" to Hawaiian Electric and this was evident by Hawaiian Electric's recommendation to lower the cost of equity by 25 basis points if the RDM/Riders are approved. However, although the proposed recovery mechanisms, <u>if approved</u>, would improve Hawaiian Electric's situation, it does not mean that the Company's underlying regulatory, economic and financial situation is improved. The decision on the Company's authorized return on equity should fully consider the Company's challenges, explained in great detail throughout this rate case, along with the impacts that approval of the RDM/Riders would bring.

Should the RDM/Riders not be approved, the underlying factors that justified the upward adjustment to the Company's ROE approved by the Commission in past rate cases would still be present and in fact would include certain challenges like the more stringent renewable portfolio standards and the Energy Agreement commitments that did not exist in the early 1990s.

For the DOD, Mr. Hill did not quantify the ROE impact of each of the elements of the Energy Agreement:

> [R]ather than attempt to project any precise "basis point" impact of HCEI, I believe its risk-reducing aspects can be appropriately recognized by this Commission shifting its view of HECO as an above average risk utility to one that, with HCEI, has lower-than average risk. As such, after the Commission determines a reasonable range for the cost of equity for HECO, it would be appropriate to utilize the lower portion of that range when awarding an allowed return. In allowing HECO a lower level of profit that it would have absent HCEI, the Commission would fulfill its obligation to provide the Company a reasonable opportunity to earn an appropriate risk-adjusted return, while providing Hawaii ratepayers some of the benefits arising from the lower operating risks afforded HECO by the public/private partnership newly codified in the HCEI agreement.

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impact the cost of capital for those purchased power projects and that the developers would pass on the costs of their projects to the power purchase agreement and those costs would get passed on to ratepayers. Tr. (Vol. VI) at 1086-87.

See DOD response to PUC-IR-172, citing DOD T-2 at 8.

Dr. Morin responded to the comments in DOD T-2 as follows:

> The impact of risk-reducing mechanisms called for in the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies ("Energy Agreement") on the Company's risk profile is reflected to some extent in the capital market data of the comparable companies, and the risk impact of these mechanisms is partially offset by several factors that work in the reverse direction, as explained more fully by Ms. Sekimura in RT-20.

HECO RT-19 at 8.

Moreover, a RDM can actually increase regulatory risks, particularly the risk of the Commission denying timely recovery if deferred balances get too large. Therefore, it is speculative as to whether, and if so how, a RDM will affect the Company's risk profile. In Dr. Morin's judgment, a maximum of 25 basis points adjustment is warranted at best.

2. Increased Business Risks

It would be unfair and unreasonable to reduce the allowed rate of return on common equity to reflect the reduction in risk resulting from risk mitigation measures, if the increased risks that create the need for the risk mitigation measures are ignored.

Act 155 and the Energy Agreement present new and increased risks to the Company. HECO RT-20 at 10. The Energy Agreement commits Hawaiian Electric to facilitate the integration of substantial amounts of clean, renewable energy into its grid and to enable electricity consumers to manage their electricity use more effectively. Uncertainty relating to the requirements for and technology of capital expenditures relating to these commitments increases business risk, in addition to the financing and cost recovery risks which increase financial risk. See HECO RT-1 at 12-14; HECO RT-20 at 10-11; Response to DOD-IR-43.

Act 155 substantially increases the electric utilities' 2020 RPS requirement from 20% to

25%, and adds a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS must be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements. See HECO RT-20 at 13-14.

Part VI of the Act directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies." In particular, the Act requires that the EEPS be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030, with interim Commission-established goals for 2015, 2020, and 2025. The Commission "may also adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies." See HECO RT-20 at14.

The Energy Agreement calls for a wide array of measures to move Hawaii decisively and irreversibly away from imported fossil fuel and towards indigenously produced renewable energy and an ethic of energy efficiency. For example, the Energy Agreement commits the Hawaiian Electric Companies to integrate substantial amounts of renewable energy into their grids, including 400 megawatts ("MW") of wind power generated on Molokai and/or Lanai and transmitted via undersea cable to Oahu. The Energy Agreement also includes a number of other undertakings intended to accomplish the purposes and goals of the Hawaii Clean Energy Initiatives, subject to Commission approval and including, but not limited to: (a) promoting through specifically proposed steps greater use of solar energy through solar water heating, commercial and residential photovoltaic energy installations and concentrated solar power generation; (b) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as new, renewable generation is installed; and (c) installing Advanced Metering Infrastructure. In addition, the Energy Agreement called for implementation of these measures on an expedited basis. HECO RT-1 at 22; HECO RT-20 at 12-13.

To achieve these very aggressive goals, the Hawaiian Electric Companies will have to successfully negotiate acceptable PPAs with project developers that naturally want to shift risk to the utility and its customers, the project developers will have to be able to successfully finance, permit, construct, obtain fuel for (in the case of biomass projects) and maintain their projects, the Hawaiian Electric Companies and project developers will have to solve the problems inherent in integrating the projects into the utility grid, and the Companies will have to finance, permit and construct the infrastructure necessary to integrate the new resources into the grid. Any risk assessment must also take into consideration the impact on Hawaiian Electric's balance sheet of the massive additional renewable energy resources being taken on by the Company through additional power purchase agreements ("PPAs"). HECO RT-20 at 11.

In addition, the Companies will need to finance the infrastructure projects necessary to integrate these resources into the electric grid without negatively impacting service reliability. Infrastructure projects are capital intensive, and the Companies' current capital expenditure budgets are already significant given increased loads and the aging infrastructure on each system.

Thus, to achieve the RPS goals and the Clean Energy objectives, as well as to meet normal service requirements, the Companies are anticipating substantial increases in actual debt (due to higher capital expenditures) and imputed debt (due to higher amounts of purchased power).[84] The Companies also are faced with rapidly rising operations and maintenance costs, in

[84] The long-term, fixed obligation nature of purchased power obligations negatively impacts risk. One measure of how investors view purchased power obligations is the "imputed debt" calculated by credit rating agencies. Although none of the Companies' existing PPAs appear on the Companies' balance sheet as long term obligations, credit rating agencies "impute debt" for these long term obligations.

addition to rising capital expenditures.

At the same time, the Hawaiian Electric Companies' credit ratings have been downgraded, and adding to their capital requirements without demonstrating support for their timely ability to earn on and recover that investment would exacerbate that situation. Timely rate relief and mechanisms which align cost recovery with cost incurrence will improve the Companies' potential to realize actual financial results consistent with allowed returns.

The agreement recognizes that these measures outlined above will increase the operating risks of the Hawaiian Electric Companies and, therefore, acknowledges that there is a need to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability, and a need to have a financially sound electric utility[85] (Energy Agreement, page 1). HECO RT-1 at 22.

The implementation of new cost recovery mechanisms (including the REIP Surcharge, the purchased power adjustment clause and the RAM mechanism) is intended, in part, to help the Companies maintain their existing credit rating and investment risk profile, by helping the utilities to recover in a more timely fashion the costs of the infrastructure and other investments required to support significantly increased levels of renewable energy, and helping the Companies achieve fair rates of return. HECO RT-20 at11.

None of the mechanisms would eliminate the need for the Companies to raise the additional capital required to fund the infrastructure projects. For example, the REIP Surcharge would provide the Hawaiian Electric Companies with a more timely recovery method for

[85] A financially strong utility is essential to the Energy Agreement's success since the utility would need to provide the infrastructure to transmit the renewable energy from the provider to the consumer and the ability of the renewable energy providers to obtain financing for their projects largely depends on the financial viability of the utility. Third-party project developers are able to finance their projects based on their purchased power agreements with credit-worthy purchasers – the electric utilities. Thus, degradation of the utility's credit quality would also be detrimental to third-party developers of renewable energy projects.

Commission approved infrastructure projects after such approved projects are placed in service, but generally would not be a means of raising capital prior to the approved projects' installation and use. HECO RT-20 at 11-12.

Many of the undertakings that will be necessary to meet the new RPS have never been attempted, in this jurisdiction, and perhaps anywhere. The credit reporting agencies have taken note of these commitments. In this regard, S&P observed in its November 26, 2008 Summary regarding Hawaiian Electric[86] that: "The level of renewable, energy-efficiency, and distributed-generation investment is significant. Just focusing on HECO (e.g., excluding goals for MECO and HELCO) the HCEI would require 148 MW of renewable installed by 2010, jumping to 890 MW by 2015. Similarly, for energy efficiency and distributed generation goals, 169 MW of measures would need to be in place by 2010, rising to 1,015 MW by 2015."[87]

Hawaiian Electric's business risk is increased by uncertainty relating to the requirements for and technology of capital expenditures relating to the Energy Agreement, in addition to the financing and cost recovery risks which increase financial risk. HECO RT-20 at 12. Thus, in its November 26, 2008 Summary, S&P also stated that, "The details on any such arrangement would be important to credit quality, as HECO's balance sheet may not be able to withstand a large infrastructure investment of this type." HECO RT-20 at 15-16; Attachment 1 of the HECO T-20 Rate Case Update.

[86] Filed in Rate Case Update HECO T-20 on December 23, 2008.

[87] S&P's credit concerns focused on three areas: the feasibility of the plan and what the ramifications are for Hawaiian Electric if it cannot meet the ambitious program outlined in the agreement, the costs of the program and whether ratepayers would ultimately be willing to bear them, and the potential impact on reliability. S&P pointed out that electric system reliability would be a major credit consideration going forward as the issues presented by integrating substantial intermittent solar, wind and distributed generation resources are not trivial. The profile concluded that the next few years are likely to be pivotal for Company credit quality as the Energy Agreement details will likely shape the Company's financial position for years to come. HECO RT-1 at 23; HECO RT-20 at 13.

3. Reflection in Market Data

Although several of the risk mitigation measures may lower Hawaiian Electric's risk on an absolute basis, they do not do so on a relative basis, as many of those mechanisms are being utilized by other utilities. HECO RT-19 at 33; response to PUC-IR-174. "[A]ny risk-mitigating impact that the risk-reducing Energy Agreement-related mechanisms could have on the Company's risk profile is reflected to some extent in the capital market data of the comparable companies, and that the risk impact of these mechanisms is partially offset by several factors that work in the reverse direction." HECO RT-19 at 34.

The approval of adjustment clauses, riders, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating and business risk scores. The experience with the operation of RDMs for electric utilities in general is very scant at this time, let alone the specific RDM variant that the Commission may adopt. HECO RT-19 at 67; HECO RT-20 at 10.

4. Impact of Specific Mechanisms

a. REIP/CEI Surcharge

The REIP/CEI Surcharge mechanism was just approved by the Decision and Order issued December 30, 2009, in Docket No. 2007-0416. It should be noted that, although a mechanism was approved, the use of the mechanism is subject to a number of stringent conditions.

In evaluating the impact of the mechanism on the cost of common equity, it is essential to recognize why the surcharge mechanism was proposed in the first place. The parties to the Energy Agreement agreed to the establishment of an REIP/CEI Surcharge to expedite cost recovery of infrastructure that supports greater use of renewable energy or utility grid efficiency.[88] The REIP/CEI Surcharge also would be used to recover costs that would normally be expensed in the year incurred and to recover costs stranded by clean energy initiatives, subject to the Commission's prior approval. HECO RT-20 at 21.

The Company needs to raise additional funds for renewable infrastructure capital and deferred software development projects, while still continuing to make other investments required to maintain the reliability of the existing system. The Company's current capital expenditure budget is already significant given the aging infrastructure. The REIP/CEI Surcharge demonstrates timely ability to earn on and recover clean energy investment and expenses which is supportive of credit quality. HECO RT-20 at 22.

Hawaiian Electric needs to be able to raise the capital in the financial markets to construct and install these infrastructure projects without degrading credit quality, or increasing the cost of capital, either of which would be detrimental to ratepayers and the development of third-party renewable energy projects. The REIP/CEI Surcharge will demonstrate regulatory support and result in more immediate cost recovery which could reduce investors' perceptions of risk (although Hawaiian Electric would still need to raise the capital in the first place). This may help to maintain credit quality and cost of capital, and mitigate the potential degradation in credit quality caused by increasing capital requirements. HECO RT-20 at 22.

In general, the Company is proposing to incur infrastructure cost for new renewable energy projects that it did not incur in the past, and which were the responsibility of the project developers instead. In taking on the responsibility for these infrastructure projects, the Company

[88] Section 29 of the Energy Agreement called for a Clean Energy Infrastructure ("CEI") Surcharge. The CEI Surcharge is equivalent to the REIP Surcharge that the HECO Companies proposed in Docket No. 2007-0416. On November 28, 2009, the HECO Companies and the Consumer Advocate filed a letter agreeing that the REIP Surcharge proposed in Docket No. 2007-0416 is substantially similar to the CEI Surcharge and that the REIP Surcharge satisfies the Energy Agreement provision that the implementation procedure of the CEI Surcharge recovery mechanism be submitted for Commission approval by November 30, 2008. Because HECO considers the REIP and CEI surcharges to be one and the same, this document refers to this surcharge as the "REIP/CEI Surcharge."

will be incurring additional risks associated with raising the capital and recovering its costs associated with the capital projects. These additional risks will be mitigated to some extent by use of the surcharge mechanism. However, the mechanism will not fully offset these risks, as the Company will now be responsible for prudently managing these projects. Thus, there will be a net increase in risk as the Company takes on the responsibility of these infrastructure projects, not a net reduction in risk.

Moreover, as pointed out in the REIP docket, Docket No. 2007-0416, when utilities do take on the responsibility for these types of projects, it is common for regulatory jurisdictions to allow the recovery of such costs through a surcharge or cost deferral mechanism.

In addition, the proposed mechanism could be used to recover the cost of the proposed AMI project. Again, however, as demonstrated in the application filed in Docket No. 2008-0303, it is not uncommon for the cost of such a project (and the offsetting benefits) to be recovered through such a surcharge mechanism.

b. <u>PPAC</u>

There are existing mechanisms for the recovery of power purchase costs, including the ECAC, which is used to recover purchased energy costs, the Firm Capacity surcharge (HRS § 269-27.2), which can be used to recover non-energy costs for non-fossil fuel PPAs between rate cases, and the use of step increases based on annualized costs in rate cases.

The PPAC is not expected to be available until the issuance of the final decision and order in this proceeding.. Because the rating agencies will then have to assess the extent to which the risk factor used to calculate imputed debt is reduced, the reduction will not be instantaneous. At the same time, the Company will be incurring additional power purchase costs as new as-available energy contracts are added. With the next rate case having a 2011 test year, the timing of the risk reduction recognition, and the resulting impact on the capital structure, should not be expected to occur before the next rate case. To the extent there is some impact prior to the next rate case, it will help the Company maintain its present credit ratings, as its rating metrics do not support its current ratings. See HECO ST-20, page 6, HECO-S-2001, page 2.

Existence of a PPAC is the mainstream position for regulated utilities across the U.S., with regulators in approximately 40 states utilizing some form of PPAC.[89] Thus, the ROE analysis undertaken by Dr. Morin (and indeed Mr. Hill and Mr. Parcell also) largely factors in the presence of such an adjustment mechanism. Accordingly, if the Commission were to lower Hawaiian Electric's authorized ROE to reflect the implementation of a PPAC, it would be punishing the Company for its PPAC vis-à-vis its industry peers, most of whom also operate with some form of PPAC. HECO RT-21 at 8; see response to DOD-RIR-27.

S&P has indicated that the risk factor used in the calculation of imputed debt would be lowered from 50% to 25%, which would cut the imputed debt in half. S&P further indicated, however, that this change would not result in any ratings upgrade, rather it would be more supportive of Hawaiian Electric's current credit rating. HECO RT-20 at 20. If the proposed purchased power adjustment clause is approved and results in a 25% risk factor assignment by S&P, there would be a $212 million decrease in imputed debt. The reduction in imputed debt would improve the Company's financial ratios as viewed by S&P or can create room to accept more imputed debt from renewable PPAs, or some combination of the two. An improvement in the debt/total capital ratio, which would move the Company toward being able to support its current credit rating, would still result in a rating implied by that ratio that is below Hawaiian Electric's current credit rating. S&P has indicated numerous times over the past few years that

89 HECO RT-21 at 8, citing "Fuel and Wholesale Power Cost Recovery," SNL - Regulatory Research Associates, October 3, 2005. [provided in Attachment 1 to response to DOD-RIR-28]

HECO's current financial ratios are weak for its current credit rating of BBB. HECO T-20 Update (December 23, 2008) at 4.

As shown in the response to DOD-IR-54, Attachment 1, page 8, at the 50% risk factor, Hawaiian Electric's total debt/total capital ratio is 56% which implies a below investment grade credit rating of BB+ (two notches below the Company's current credit rating of BBB) for the total debt/total capital ratio. At the 25% risk factor, Hawaiian Electric's total debt/total capital ratio would be 51%, which improves the implied credit rating to BBB- for the total debt/total capital ratio; however this implied rating based on the total debt/total capital ratio is still one notch below the Company's current credit rating of BBB, and just above a non-investment grade credit rating. A reduction in risk factor would improve the total debt/total capital ratio which will help move the Company's financial profile to be more supportive of its current credit rating.

Further, Hawaiian Electric anticipates increases in its actual debt as well as imputed debt as a result of numerous pending and contemplated long-term arrangements. In addition to imputed debt related to PPAs, S&P also imputes debt for all operating leases. HECO T-20 Update (December 23, 2008) at 5.

A decrease in imputed debt resulting from a decrease in S&P's risk factor assignment to purchased power may allow the Company to accommodate the anticipated increase in actual debt and imputed debt without degrading its financial profile and existing credit quality.

In summary, although the implementation of a purchased power adjustment clause is expected to improve the Company's credit quality, it is not expected to result in a credit rating improvement. Rather, the improvement in credit quality will help the Company to maintain its existing credit rating. To serve ratepayers as contemplated in the Energy Agreement as well as meeting normal service requirements, the Company is anticipating increases in actual debt and imputed debt. Any improvement in credit quality will be diminished to the extent that any decrease in imputed debt is offset by increases in actual debt and imputed debt. HECO T-20 Update (December 23, 2008) at 6.

c. **Decoupling**

With respect to decoupling, the Energy Agreement explicitly provides that:

> The transition to Hawaii's clean energy future can be facilitated by modifying utility ratemaking with a decoupling mechanism that fits the unique characteristics of Hawaii's service territory and cost structure, and removes the barriers for the utilities to pursue aggressive demand-response and load management programs, and customer-owned or third-party-owned renewable energy systems, and gives the utilities an opportunity to achieve fair rates of return. (HCEI Agreement at 32)

The sales decoupling mechanism should help to reduce earnings variability and thereby reduce operating risk, all else being equal. Unlike PPACs, sales decoupling is not yet the norm for regulated utilities across the U.S. – the Wall Street Journal recently reported that "at least a dozen states, including New York, North Carolina and California, have decoupling measures in place, while 26 others – from Maine to Idaho and Nevada – are reviewing or implementing them."[90] Decoupling has not yet reached sufficient critical mass whereby it would inherently be captured by traditional ROE analysis.

The impact of the decoupling mechanism on financial integrity and rate of return on equity are discussed by Mr. Fetter in RT-21 and Dr. Morin in RT-19. Mr. Fetter was of the opinion that a lowering of authorized ROE is appropriate if revenue decoupling is approved here. A 25 basis point reduction, as proposed by Dr. Morin, seems to be the right correction, while Mr. Parcell's proposed 50 basis point drop seems too significant a downward move for a policy that is strongly supported by many environmentalists and elected and appointed policymakers. HECO RT-21 at 9-10, see response to DOD-RIR-30.

[90] "Less Demand, Same Great Revenue," Wall Street Journal, February 8, 2009. [provided in response to CA-RIR-40]

It should also be recognized that sales decoupling was <u>not</u> available during the 2009 test year, even though the parties stipulated to the introduction of sales decoupling on an interim basis. Moreover, as explained in a June 30, 2008 report to the Minnesota Public Utilities Commission titled, "Revenue Decoupling Standards and Criteria," improvements in utility bond ratings due to decoupling generally require several years to play out and the consequent benefits for customers are therefore slow to materialize. HECO RT-20 at 18.

The proposed RAM component of decoupling is one of a number of mechanisms that can be used to adjust rates. The most common mechanism used is rate cases, and the primary benefit of having a RAM is having a reduction in the number of rate cases. The proposed RAM is relatively conservative, and the availability of the RAM mechanism is not expected to result in an increase in overall rates versus the use of rate cases. Thus, the impact of the RAM on the earnings variability is unknown at this point in time.

Hawaiian Electric's entire financial picture needs to be taken into account when evaluating the Company's risk. Many of HECO's comparable utilities already have decoupling mechanisms in place. Mr. Fetter discusses this in his testimony. <u>See</u> HECO T-19 at 9. As a result, although an increase in HECO's ROE would likely be warranted in the event the Company's decoupling proposal were rejected, this does not imply a similar downward adjustment due to the approval of such a mechanism. HECO RT-20 at 18.

d. <u>Other Jurisdictions</u>

Research on the effect of the proposed decoupling mechanism on the cost of capital was undertaken at the request of the Hawaiian Electric Companies. Based on a review of the orders of U.S. regulatory commissions from 2007 to 2009 that addressed the target ROEs for the currently operating decoupling plans for electric utilities PEG tabulated instances in which the decision included an explicit adjustment to the target ROE due to the inclusion of a decoupling plan.[91] Differences were calculated separately for vertically integrated and transmission and distribution ("TDUs") utilities. This research found that an explicit adjustment to the target ROE was made in only 5 of 16 cases. Decoupling led to an average reduction in target ROE of 26 basis points. More detailed results of this exercise appear in Attachment 1 to the response to PUC-IR-115.

As a second exercise, PEG compared the average of the target ROEs applicable to the recent electric utility decoupling plans with the average target ROEs approved in the same year for electric utilities not operating under decoupling.[92] Differences were calculated for TDUs separately. This research shows that the target ROEs for utilities with decoupling plans were 19 basis points lower on average. More detailed results of this exercise appear in Attachment 2 to the response to PUC-IR-115.

Recent Nevada testimony for Southwest Gas reported on the results of a similar survey of U.S. gas distributors.[93] The study considered the target ROEs of 26 approved decoupling plans that were identified by the American Gas Association ("AGA") in its July 2008 *Natural Gas Rate Roundup* (see Attachment 5). Of the 26 decisions, only seven made an explicit reduction to the target ROE. The average downward adjustment was 12.5 basis points. In two cases, the Commission explicitly rejected an adjustment due to decoupling. In the case of Baltimore Gas

[91] Hawaiian Electric requested that Pacific Economics Group ("PEG"), its decoupling consultant, provide information on the experience in other jurisdictions with respect to the impact of decoupling, including decoupling without a Rate Adjustment Mechanism, on the cost of equity. PEG excluded from this survey the current rate plans for two Vermont utilities, Green Mountain Power and CVPS. These plans have attributes of revenue decoupling plans but were not acknowledged to be decoupling plans by regulators. In the case of California decoupling plans, decisions concerning target ROEs are made in hearings that are separate from rate case hearings. PEG used the most recent hearing of this kind in their survey.

[92] In the case of California decoupling plans, decisions concerning target ROEs are made in hearings that are separate from rate case hearings. PEG used the most recent hearing of this kind in our survey.

[93] Response to PUC-IR-115, <u>citing</u> Prepared Direct Testimony of Daniel G. Hansen on Behalf of Southwest Gas Corporation in support of their 2009 Nevada General Rate Case Application in Docket 09-04003, April 3 2009.

and Electric ("BG&E") gas operations, a decoupling adjustment to ROE was rejected because both Staff and BG&E's witnesses had used proxy group data that incorporated the reduction in risk for weather or conservation mitigation.[94] For Consolidated Edison's gas operations, decoupling was part of an overall rate case and was resolved by a settlement which excluded a reduction in ROE due to decoupling.[95]

The Nevada testimony also compared the target ROEs of gas utilities operating under any of three approaches to decoupling – full balancing account decoupling (similar to that jointly proposed by Hawaiian Electric and the Consumer Advocate), weather normalization, and SFV pricing – to the target ROEs of gas utilities operating without any of these mechanisms. The source of the ROE data was an AGA database. Utilities with at least one of these three forms of decoupling had target ROEs that were, on average, 30 basis points lower than those approved in the same year for utilities operating without such mechanisms. This result was somewhat sensitive to the distribution of decoupling approval decisions over the years of the sample period. Decoupling decisions were bunched in a year of especially low average ROEs. When this was adjusted for statistically, the average difference was 25 basis points. The results were also sensitive to the typical level of ROE in the states where decoupling plans were approved. For example, commissions that approved decoupling also tended to be commissions that granted low target ROEs. When this was adjusted for statistically in addition to the time effect, the typical target ROE was actually 6 basis points *higher* with decoupling than without but not significantly different from zero. Response to PUC-IR-115.

5. <u>Effect of Eliminating Risk Adder</u>

In rebuttal (and in his update), given the prospect of approval of the proposed

[94] Response to PUC-IR-115, <u>citing</u> Order 80460, p.67 in Case 9036 before the Public Service Commission of Maryland dated December 21, 2005.

[95] Response to PUC-IR-115, <u>citing</u> Case 06-G-1332, p.27-29 dated September 25, 2007.

RDM/Riders, Dr. Morin did not adjust the cost of equity estimates to account for the fact that Hawaiian Electric's risk is higher than the industry average. Instead he stated that, "[s]hould the Commission allow the Company to establish and implement a revenue adjustment mechanism as proposed in the joint decoupling proposal filed by the Company and the Division of Consumer Advocacy in the decoupling proceeding (Docket No. 2008-0274), and given the various riders discussed earlier, the need for such a risk premium is unnecessary, and HECO's risk is comparable to the industry average." HECO RT-19 at 72-73.

F. CREDIT RATINGS AND NEED FOR REGULATORY SUPPORT

1. Introduction

When Hawaiian Electric filed its instant Application in July 2008, the Company had corporate credit ratings of BBB by Standard & Poor's ("S&P"), and Baa1 by Moody's Investors Services ("Moody's"). HECO T-20 at 10; see HECO-2008; HECO-2009.

According to information provided by the Consumer Advocate's witness, Mr. Parcell, of the 60 electric utilities and combination gas and electric utilities covered by AUS Utilities Reports, there were 38 utilities with S&P credit ratings higher than Hawaiian Electric's BBB rating, 10 other utilities with the same BBB rating, and 11 utilities with ratings lower than BBB. See CA-T-4 at 23-24. If Hawaiian Electric's S&P rating were downgraded to BBB-, however, there would be 48 utilities with S&P ratings higher than Hawaiian Electric, 5 other utilities with ratings the same as Hawaiian Electric, and 6 utilities with ratings lower than Hawaiian Electric.

Financial guidelines for Hawaiian Electric point to a BBB- rating without relief, and BBB with rate relief. HECO T-20 at 46-48. Prior to May 2007, S&P's corporate credit rating of Hawaiian Electric had been BBB+. In May 2007, S&P downgraded the Company to BBB. S&P has indicated numerous times over the past few years that the Company's financial ratios are weak for its current credit rating of BBB. See HECO T-20 at 7-8. In May 2008, S&P maintained the Company's BBB credit rating, but lowered its business risk profile assessment from "excellent" to "strong". See HECO T-20 at 10-11.

More recently, S&P's Research Update, dated May 27, 2009, revised the Company's outlook to negative (from stable), noting that the Company's credit metrics are only marginally supportive of the current BBB credit rating. S&P also lowered the Company's short-term ratings to 'A-3' from 'A-2'. HECO T-20 at 5-6; see HECO-S-2001. One would anticipate that a downgrade of the Company's credit rating would negatively impact the cost of financing the Company's capital programs and could also impact the cost of capital for projects developed by independent power producers, which cost impacts could ultimately be passed on to ratepayers. See Tr. (Vol. VI) at 1085-87 (Parcell).

In May 2009, S&P also lowered Hawaiian Electric's short-term debt credit rating from A2 to A3. This prevented the Company from accessing the commercial paper market and resulted in the Company borrowing on its line of credit, which was established to merely be a back-up to commercial paper borrowings, to meet its short-term debt needs. Tr. (Vol. VII) at 1240-1241. See also HECO-S-2001 at 2.

2. Importance of Credit Ratings

a. Need for Financial Strength

It is critical for the Company to maintain its financial strength. Investors are very sensitive to financial strength considerations when they decide where to invest their money. If Hawaiian Electric's financial strength is not maintained, more risk adverse investors will invest their money elsewhere. This, in turn, will have negative implications for the Company's customers because it will reduce the demand for the Company's securities and will increase its cost of capital. Further, under adverse market conditions, it may be difficult to attract capital. HECO T-20 at 9.

In view of: (1) Hawaiian Electric's planned capital investments; (2) the extent of the Company's purchased power obligations; and (3) the likely cost of meeting the Company's future renewables and DSM mandates, the Company faces a number of specific current challenges that make it particularly imperative that the Company improve (or at a minimum maintain) its financial strength. See HECO T-21 at 4; HECO T-20 at 9-10.

For example, the Company faces high capital requirements to maintain aging infrastructure, to add the new infrastructure necessary to reliably integrate renewable energy resources, and to establish the platform for customers to effectively manage their use of electricity. In order to raise capital at a reasonable cost, the Company needs to demonstrate the ability to repay investors at expected rates of return. HECO T-20 at 9.

In addition, the Company has significant power purchase obligations which will increase as new and renewed purchased power contracts are entered into. The Company recently issued a request for proposals for up to approximately 100 megawatts of renewable energy on Oahu. HECO's financial strength (as measured by the Company's ability to fulfill its obligations to suppliers and meet the return expectations of investors) is key to attracting bidders for new renewable energy developments because independent power producers rely on the Company's credit in order to finance their projects. HECO T-20 at 9-10.

b. Credit Ratings

One of the principal measures of a company's financial strength is its credit rating. Credit ratings are issued by independent rating agencies, such as S&P, Moody's and Fitch. A credit rating is an impartial opinion of the general creditworthiness of a company (issuer credit rating), or the creditworthiness of a company with respect to a particular security (issue-specific credit rating), such as secured debt which provides investors with the backing of tangible assets as security. Credit rating agencies evaluate the investment risk in commercial paper, secured and unsecured debt, hybrid securities, and preferred stock. The rating for each security reflects the investment risk in that security, given the rating agency's overall evaluation of the financial condition of the company and the particular characteristics of the individual security. HECO T-20 at 10.

Hawaiian Electric's BBB rating by S&P is of particular concern because that rating puts the Company only one notch above the minimum "investment grade credit rating".[96] It is important for the Company to maintain credit ratings that are above the lowest "investment grade"[97] credit rating level (i.e., above BBB- for S&P and above Baa3 for Moody's). Maintaining a credit rating that is above the "investment grade" floor will allow some comfort that the Company can maintain at least an "investment grade" credit rating if the Company were to face an operational or financial setback that could cause a rating downgrade. Under such a circumstance, it is important to maintain at least an "investment grade" credit rating, as: (1) maintaining at least an "investment grade" credit rating helps to minimize electric rates by lowering the cost of capital to the Company; and (2) maintaining at least an "investment grade" credit rating gives the Company the ability to consistently attract new capital on reasonable terms, whatever the current state of the financial markets. See HECO T-20 at 10-11.

Mr. Parcell, the Consumer Advocate's rate of return witness, agreed that the objective should be for the Company to stay at BBB or above because once the credit rating goes below BBB, the Company will not only incur higher costs but will also have

[96] S&P's rating of BBB- or higher is considered "investment grade".
[97] S&P's rating of BBB- or higher or Moody's rating of Baa3 or higher.

an issue with availability of capital. Tr. (Vol. VII) at 1323-24.

The Company's current credit ratings impact its ability to integrate more renewable energy into its system. The Company's credit rating is relatively low given the significant challenges it faces. Hawaiian Electric must work to improve its credit rating in order to: (1) ensure access to the capital markets at a reasonable cost necessary to maintain existing service and to invest in infrastructure necessary to integrate more renewable energy in HECO's system and (2) attract renewable developers from which HECO can procure more renewable energy. HECO T-20 at 12.

3. Factors Affecting Credit Rating

In order to determine a company's credit rating, the rating agencies evaluate a wide range of qualitative and quantitative factors that affect the company's credit quality. This assessment considers both the business risks and the financial risks of the company (see HECO T-20 at 12), which are discussed above. However, S&P notes that the ratings indicated by assigned business and financial risk profiles are evaluated in conjunction with other qualitative factors in determining a company's credit rating. See HECO T-20 at 46; HECO-2014; response to DOD-RIR-15, Attachment 1.

4. Need for Regulatory Support

Regulation is a critical component of business risk that underlies a utility's creditworthiness, and decisions by the regulators can profoundly affect financial performance. Regulators have authority over the majority of the industry's returns. HECO T-20 at 13. Thus, virtually every time a rating agency modifies or affirms a utility credit rating, mention is made of the regulatory body within the relevant jurisdiction and how its policies are factored into the rating determination. HECO RT-21 at 11.

From an investor's standpoint, regulators' decisions regarding rates of return, equity allowed and rate base growth can play a large role in the economic value of an investment. Before major investors will put forward substantial sums of money, they want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly changing industry and that the regulators' decision-making will be fair and have a significant degree of predictability. HECO T-21 at 10.

Recent years have exhibited a dramatic resurgence in the importance of regulation through the eyes of investors in connection with: (1) expanding capital expenditure programs (e.g., new capacity and upgrades); (2) environmental compliance requirements; (3) a dearth of rate cases in the 1990s and early 2000s; and (4) large amounts of new equity capital to be required by the industry. HECO T-20 at 13. In addition, the utility industry has experienced a steady escalation in risk over the past ten years, as evidenced by the steady rise in utility betas, standard deviation of returns, bond downgrades, and other measures of risk. See response to DOD-IR-25. As a result, regulation has become a major factor – and to many investors, the single most important factor – in utility investment-related decision making. HECO T-20 at 13.

Accordingly, timely recovery of actual costs with a fair return should be the regulatory goal, as it is consistent with the regulatory compact, and works to minimize regulatory lag which financially injures a regulated utility with no real remedial recourse. Both utility customers and investors benefit when the Company receives sustained regulatory support, as such support can go a long way toward allowing the Company to improve its credit ratings. See HECO T-21 at 4.

S&P highlighted the continuing importance of regulation to the financial community in two relatively recent reports. In a report entitled "New York Regulators' Consistency Supports Electric Utility Credit Quality," S&P offered general thoughts on the importance of regulation that apply within but also far beyond the borders of New York State:

> Regulation defines the environment in which a utility operates and greatly influences a company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of supportive regulation. Conversely, an unpredictable or antagonistic regulatory environment can undermine the financial position of utilities that are operationally very strong.
>
> To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory policies. . . .[98]

In an earlier report, S&P provided guidance as to how it assesses whether a regulatory body can be considered supportive:

> In assessing the regulatory environment in which a utility operates, [S&P's] analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief.[99]

S&P highlighted the continuing importance of regulation to the financial community in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry" [provided in response to CA-RIR-41]:[100]

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

S&P's current assessment of the Hawaii Commission is in the middle of the pack –

[98] HECO T-21 at 11, quoting S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005. [Provided in Attachment 1 to CA-IR-23]

[99] HECO T-21 at 11, quoting S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005. [Provided in Attachment 2 to CA-IR-23]

[100] HECO RT-21 at 10.

ranked behind 20% of all state commissions and higher than 40% of other state commissions, in a category entitled "Credit Supportive".[101] HECO RT-21 at 11.

5. Regulatory Support Under Current Economic Conditions

In these tough economic times in particular, investors are paying very close attention to the Company's ability to access cash. HECO RT-20 at 24. Instability in the financial markets has created challenges to an extent that has never existed in the past. HECO T-21 at 6. The financial crisis has resulted in the capital markets being more volatile than any time since the 1930s, and unprecedented swings in yield spreads.[102] See HECO RT-19 at 4-6, 26; HECO T-21 at 6-7.

Utilities operating within today's more stressful environment and their regulatory authorities should strive to minimize the regulatory uncertainties that could affect a utility's financial profile, its credit ratings, and thus its access to capital on favorable terms. HECO T-21 at 6; HECO RT-20 at 24; response to CA-IR-21.

The negative effects from the current financial crisis on the overall economy will not be transitory nor quick to turn around. And the utility sector, even if positively "stimulated" with federally supported infrastructure spending, must still deal with delinquent accounts and uncollectibles growing across virtually the entire regulated energy sector, deeply eroded pension plan values, soaring health care funding requirements, and financing activity that is subject to greater volatility with regard to both availability and cost. The negative events during the Fall of

[101] S&P Research: "Credit FAQ: Standard & Poor's Assessments of Regulatory Climates for U.S. Investor-Owned Utilities," November 25, 2008. [provided in response to CA-RIR-42]

[102] The spreads between A-rated utility versus ten-year T-Bonds increased from approximately 1.5% in January 2008 to as high as 4.0% in December 2008. The spreads between BBB-rated utility versus thirty-year T-Bonds increased from less that 2.0% in January 2008 to over 4.0% in December 2008. HECO RT-20 at 25.

2008 illustrate clearly that 'BBB' category utilities are much more vulnerable than 'A' category utilities when capital markets are in a state of upheaval. HECO T-21 at 8.

For the past three years, authorized ROEs for regulated electric utilities have slowly moved upward from among the lowest levels ordered by state utility regulators during the past two decades – tracking at 10.29% for 2006, 10.32% in 2007, and 10.34% during 2008.[103] Not surprisingly, after the global financial collapse during the Fall of 2008, early signs in 2009 pointed to higher authorized ROEs to help ensure the financial stability of regulated utilities, especially those which, like Hawaiian Electric, hold credit ratings within the "BBB" category. HECO RT-21 at 2; HECO-R-2101.

Hawaiian Electric's ROE should not be decreased during times of volatility and large bond spreads such as these, because of the risk of a potential downgrade. HECO RT-20 at 25. If the ROE authorized in this case is too low, then the Company would likely have to increase debt financing to offset weakness in interest among equity investors. Under such a scenario, the growing debt burden would likely pressure Hawaiian Electric's credit ratings, with the possibility of a downgrade. Such a negative action would further diminish the Company's appeal to equity investors, while raising the cost of debt financing, which ultimately would translate into higher rates. HECO T-21 at 16; see HECO RT-20 at 25-26; response to CA-RIR-21. As Dr. Morin pointed out, in this regard, the interests of ratepayers and investors are one and the same. Tr. (Vol. VII) at 1222.

At the evidentiary hearing, both Dr. Morin and Mr. Parcell cautioned against approval of an ROE that would result in a downgrade, as "the return back to being upgraded again is a very long and arduous road." Tr. (Vol. VII) at 1131, 1324-25.

[103] Edison Electric Institute, 2008 Financial Review at p. 34. [provided in response to DOD-RIR-25]

The Company's credit ratings are slightly below average and remain fragile. HECO RT-19 at 33. The Company has numerous regulatory actions pending before the Commission that will impact the credit rating agencies' assessment of Hawaiian Electric's regulatory risk. The Company needs to continue to obtain regulatory rulings that: (1) give the Company a realistic opportunity to earn a fair return, (2) provide full cost recovery of prudently incurred costs on which the Company's investors make no profit, (3) assure cost recovery of and on necessary capital investments, and (4) provide a fair return on prudent investments. Regulatory decisions that suggest the utility will not have regulatory support (e.g., rulings which are delayed, inconsistent with prior decisions, or create uncertainty) would increase the Company's risk profile, and thus place into jeopardy Hawaiian Electric's current credit ratings. A downgrade of those ratings would increase the Company's cost of capital, and thus, ultimately, the rates that customers are required to pay. See HECO T-20 at 14, 17; HECO T-21 at 10-11.

6. Actual Earned Returns and Timely Cost Recovery

The Company's actual rates of return on simple average rate base and on simple average common equity as filed with the Commission have been (HECO T-20 at 4):

	Return on Rate Base	Return on Common Equity
2005	6.20%	6.92%
2006	6.78%	7.61%
2007	4.92%	4.52%

The Commission set interim and final rates in Hawaiian Electric's 2005 test year rate case (Docket No. 04-0113) based on a 8.66% rate of return on rate base ("ROR") and a 10.7% rate of return on common equity ("ROE")[104] and set interim rates in HECO's 2007 test year rate case (Docket No. 2006-0386) based on a 8.62% ROR and 10.7% ROE.[105]

[104] Interim D&O No. 22050, filed September 27, 2005 in Docket No. 04-0113; Amended Proposed D&O No. 23768, filed October 25, 2007 in Docket No. 04-0113; D&O No. 24171, filed May 1, 2008 in Docket No. 04-0113.

[105] Interim D&O No. 23749, filed October 22, 2007, in Docket No. 2006-0386.

Hawaiian Electric's ROE in 2008 was 8.07% for ratemaking,[106] over 260 basis points lower than the authorized return of 10.7%. As of June 30, the 12 months trailing ROE was only 6.4% (on a ratemaking basis),[107] 410 basis points less than the interim ROE of 10.5%. As of September 30, 2009, the 12 months trailing ROE was only 6.52% (on a ratemaking basis).[108]

There have been a number of reasons why have the returns that Hawaiian Electric has actually earned have been so much lower than those used to establish rates in its recent rate cases. First, although interim rate orders in the Company's most recent rate cases[109] have generally been supportive and within legislatively mandated deadlines, the lag between the start of the test year and the interim rate relief has not allowed Hawaiian Electric the opportunity to actually earn the allowed return in the test year. HECO T-20 at 4-5.

Although one could argue that the failure to achieve adequate returns was due to the timing of the Company's rate case applications, it would have been difficult for the Company to achieve its authorized returns even if it had filed its rate case applications earlier. As explained by Mr. Robert Alm in HECO T-1, even if the Company were to file its rate case at the earliest date allowed under the Commission's rules, as it has done in this rate case (i.e., six months before the beginning of the test year), the statutory deadline for an interim decision would be May or June.[110] Because of this structural lag, it would

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[106] Rate of Return on Rate Base and on Common Equity for December 2008 (ratemaking method), filed February 27, 2009.

[107] Rate of Return on Rate Base and on Common Equity for December 2008 (ratemaking method), filed August 7, 2009.

[108] Rate of Return on Rate Base and on Common Equity for December 2008 (ratemaking method), filed November 2, 2009.

[109] Interim D&O No. 22050, filed September 27, 2005 in Docket No. 04-0113 and Interim D&O No. 23749, filed October 22, 2007 in Docket No. 2006-0386.

[110] Section 6-61-87(4) of the Hawaii Administrative Rules states: "... (A) If an application is filed within the first six months of any year, the test year shall be from July 1 of the same year through June 30 of the following year; or (B) If an application is filed within the last six months of any year, the test year shall be from January 1 through December 31 of the following year..." Section 269-16 of the Hawaii Revised Statutes states that the Commission must render its interim decision within ten

be difficult for the Company to achieve its authorized return in the test year even if it were to file its rate case application at the earliest allowed date since by May, at least a third of the year will have passed. See HECO T-20 at 5-6.

Second, kWh sales were lower than forecast in the rate cases, resulting in insufficient revenue dollars, which deteriorated returns.[111] Actual sales in 2005 and 2006 were less than the sales assumed in the 2005 rate case. Additionally, actual sales in 2007 were less than the sales assumed in the 2007 rate case. Since rates were established based on the rate case sales assumptions, but actual sales were lower than the rate case sales assumptions, actual revenue dollars were less than the test year revenue requirements (adjusting for ECAC revenues which are based on actual sales). See HECO T-20 at 6.

Third, the financial dilemma that regulatory lag creates goes beyond the test year because costs are increasing faster than revenue is increasing. In 2006, Hawaiian Electric received a full year of the 2005 test year interim rate increase but still was unable to achieve its authorized returns. Likewise, in 2008, the Company had a full year of the 2007 test year interim rate increase, but faced higher O&M costs than what were included in the test year revenue requirement. As long as cost increases outpace sales growth and revenues are based on sales, the Company will be in an endless cycle of catch-up, struggling to achieve a fair return on its utility property. See HECO T-20 at 6.

In the context of traditional ratemaking proceedings, providing Hawaiian Electric with an

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months; eleven months if evidentiary hearings are incomplete. Ten or eleven months from the July 3, 2008 filing date of this application would be May 3, 2009 or June 3, 2009.

[111] Hawaiian Electric has experienced a trend of decreasing sales since 2004. See Dr. Willoughby's discussion of actual sales not meeting sales forecasts in HECO T-2. The Company's recorded September 2009 year-to-date energy sales are 3.5% less than recorded year-to-date energy sales of a year earlier and 1.6% less than the year-to-date energy sales forecasted for the 2009 test year. HECO Hearing Exhibit 3, Docket No. 2008-0083, HECO T-2, page 2, re-filed (on a confidential basis) November 3, 2009.

opportunity to realistically and consistently earn its approved rate of return requires, at a minimum, timely review and final decision-making for its rate cases. See HECO T-21 at 5, 18-19. However, if the approved return cannot be achieved through the traditional ratemaking process, then the Company needs alternative mechanisms that time cost recovery with cost incurrence. See HECO T-20 at 6, 23; see HECO T-21 at 5, 26-27.

Alternative cost recovery mechanisms approved for Hawaiian Electric in prior Commission proceedings, such as the ECAC, have been viewed very favorably by credit ratings agencies.

S&P recently explained how recovery mechanisms, such as the PPAC, can play a key role in providing a regulated utility with timely recovery of prudent expenditures, thereby helping to mitigate the negative effects from regulatory lag:

> [W]e believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why [S&P] views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.[112]

Thus, the Company's ability to continue to implement such mechanisms (including obtaining final approval of the OPEB tracking mechanism approved on an interim basis in Docket No. 2007-0386) will play an ongoing role in the Company's future credit quality. See HECO T-20 at 14, 26-33; HECO T-19 at 57-59; HECO T-21 at 5, 17, 22-26. If and when they are approved by the Commission, additional mechanisms for alternative cost recovery such as the PPAC, RBA and RAM could similarly result in favorable future impacts on the Company's credit quality. See HECO T-20 at 35-41, 49; HECO T-20 Rate Case Update; HECO RT-20 at

[112] HECO RT-21 at 11, quoting S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009. (See HECO-R-2008.) DOD-RIR-27 (RT-21, at 8, lines 10-12).

20; HECO ST-20; response to PUC-IR-131; HECO RT-21 at 8.

O VI. COST OF SERVICE AND RATE DESIGN

1. COST OF SERVICE

In its direct testimony, Hawaiian Electric presented the results of the cost of service studies using two different methodologies of classifying distribution network costs: 1) the minimum system method that Hawaiian Electric, HELCO, and MECO have used in all of their respective recent rate cases, and 2) the Consumer Advocate's method of classifying all distribution network costs as demand-related. HECO T-22 at 2-3.

A cost of service study is a tool used to determine the cost responsibility of the different rate classes served by Hawaiian Electric for ratemaking purposes. Two types of cost of service studies were prepared for this proceeding, one based on embedded or accounting costs, and the other based on marginal energy costs. Although both studies reflect the costs of providing service, the procedure and emphasis of each of these two studies are different. HECO T-22 at 5. An embedded cost of service study, referred to as a "cost of service study", is a process used to categorize and allocate the total utility costs of providing service (the utility's total revenue requirements) to the various rate classes in order to determine each class's cost responsibility. In contrast, a marginal cost study determines the change in the utility's costs of providing service due to a unit change in kilowatts, kilowatthours, or the number of customers served by the utility. HECO T-22 at 5-6.

The Consumer Advocate recommends that the Commission discount any results from the minimum system method and rely only upon cost of service study scenarios that classify all distribution network costs as 100% demand costs. CA-T-5 at 13. The Department of Defense finds that the Hawaiian Electric class cost of service study that incorporates the minimum system method for classifying distribution costs is reasonable. DOD-300 at 9.

For settlement purposes, the Parties concurred that agreement on a cost of service methodology is not a requirement to settle the case. The agreements on revenue allocation and rate design presented below are reasonable given the results of the cost of service studies based on the two methodologies presented by Hawaiian Electric. Hawaiian Electric agreed to continue to present the results of its cost of service studies in its next rate filing using the two different methods, reflecting the minimum system method and alternatively the full demand classification of distribution network costs. Settlement Exhibit at 84.

Inter-Class Allocation of Rate Increase

In its direct testimony, Hawaiian Electric proposed to allocate the increase in revenues as an equal percentage increase to current effective revenues at all rate schedules. HECO T-1 at 20. The Consumer Advocate supported an equal percentage distribution of any revenue increase in this Docket. CA-T-5 at 34. The Department of Defense argued that an across-the board increase is not appropriate because it will not move rates closer to cost and, in fact, would exacerbate existing subsidies. DOD-300 at 20.

For settlement purposes, the Parties agreed to allocate any interim increase in electric revenues to the existing rate classes in the percentages shown below:

Schedule R	35.74%
Schedule G	4.37%
Schedule J	33.86%
Schedule H	0.55%
Schedule PS	8.64%
Schedule PP	15.17%
Schedule PT	1.03%

Schedule F	0.64%
Total	100.00%

Settlement Exhibit at 84-85.

In addition, the Parties agreed to allocate the interim increase in electric revenues assigned to Schedule PP customers such that the Schedule PP customers who are Directly Served from a substation are assigned a revenue increase that is 50% of the overall revenue percentage increase that the interim increase represents. Settlement Exhibit at 85.

In its direct testimony, Hawaiian Electric proposed to implement the Interim Increase (and the CIP CT-1 step increase, which is no longer being proposed as a result of the global settlement) on a cent per kilowatt-hour basis. HECO T-1 at 21 and HECO T-22 at 56-57. The Consumer Advocacy agreed with this approach. CA-T-5 at 55. For settlement purposes, the parties agreed to implement the interim rate increase on a cents per kWh basis. Settlement Exhibit at 85.

In its Interim Decision and Order, the Commission stated a concern about the justness and reasonableness of the Parties' proposed allocation of cost increases, because the increases appear to depart from the traditional functionalization, classification, and allocation methodology used to determine rates for each customer class. IDO at 15.

In its supplemental testimony, the Company stated that it has employed functionalization, classification, and allocation methodologies to allocate the proposed costs and rate base to customer classes. HECO ST-22 at 2-4. Functionalization, classification, and allocation methodologies are not used to determine rates for each customer class. Rather, the proposed allocation of revenue increase to customer classes is made by balancing the revenue increase assigned to the classes and the rates of return proposed for the classes with the rates of return calculated for each of the classes before the revenue increase is allocated. HECO ST-22 at 2.

The class rates of return, before the revenue allocation is made, are determined by allocating cost to serve each customer class, based on functionalization, classification, and allocation methodologies, and comparing them with the class' estimated revenues at current effective rates. An estimated rate of return on rate base is calculated for each class and for the Company. A rate of return index at current effective rates is calculated as the ratio of the class rate of return divided by the rate of return for the Company. The rate of return index at current effective rates is a measure of how the estimated class revenues at test year sales and current rates compare with the cost of service allocated to the class; a rate of return index value of 100% means that the class revenues recover the allocated class costs, and the class earns the same rate of return as the Company as a whole. HECO ST-22 at 2-3.

The proposed revenue increase establishes a proposed rate of return for the Company. The allocation of the revenue increase to rate classes is intended to move each class rate of return index at proposed rates closer to 100% than its respective class rate of return index at current effective rates. The proposed revenue increase is allocated such that each class' revenues are closer to the class cost of service at proposed rates, including a rate of return at the proposed Company rate of return. HECO ST-22 at 3.

In its direct testimony, Hawaiian Electric identified a list of rate design concept considerations. HECO T-22 at 22. The considerations of revenue stability and impact on customers apply to the allocation of proposed revenue increases to classes as well. In the class revenue increase proposal, Hawaiian Electric tries to achieve the rate of return goals described above, but limits the movement of the class rate of return index at proposed rates in order that the class revenue increase impacts do not differ by extremes or appear to burden a certain class or classes unreasonably. HECO ST-22 at 3.

The Parties have agreed to the percentage allocation of any final increase in electric revenues to the proposed six rate classes. Settlement Exhibit at 85. In HECO ST-22, Attachment 1, page 1, the proposed revenue allocation to classes, based on the Settlement Exhibit percentages, and the class rates of return and rate of return index at proposed rates are presented for the cost of service scenario based on the minimum system study. For all rate classes, the rate of return index at proposed rates has moved higher or lower towards 100% from the rate of return index at current effective rates. This is accomplished by assigning a revenue percentage increase to Schedule R, Schedule J, and Schedule F that is higher than the Company total percentage increase, since these classes had rate of return index values at current effective rates of less than 100%. The revenue percentage increase assigned to Schedule G, Schedule DS, and Schedule P is lower than the Company total percentage increase, since these classes had rate of return index values at current effective rates of greater than 100%. In addition, the smallest revenue percentage increase assigned (to Schedule DS) is about 50% of the Company total percentage increase, while the largest revenue percentage increase assigned (to Schedule J) is about 125% of the Company total percentage increase, which demonstrates that the proposed class revenue increases, while spread differently to different classes, are not extreme.

Based on the foregoing, the proposed revenue allocation to proposed rate classes that is presented in the Settlement Exhibit is reasonable, because it balances the impact to customer classes while moving each class' revenues closer to its proposed cost of service, which is determined based on functionalization, classification, and allocation methodologies. HECO ST-22 at 2-4.

In its Interim Decision and Order dated July 2, 2009, the Commission also stated a concern that implementing the interim rate increase on a cents-per-kwh basis could inappropriately include fixed costs in the variable component of rates. IDO at 16. In consideration of the Commission's concerns about the implementation of the interim rate increase, the Company, in its Revised Schedules Resulting from Interim Decision and Order, filed July 8, 2009, in Exhibit 2A, page 1, proposed to implement the interim rate increase as percentage increases assigned to customer classes, as has been done in the implementation of interim rate increase in the most recent rate cases for the Hawaiian Electric Companies. By implementing the interim increase as a percentage, the underlying rate design and recovery of costs through customer, energy, and demand charges based on the Hawaiian Electric 2005 test year rate design approved by the Commission remains unchanged. Changes to the rate design and to the recovery of costs through the rate schedule charges would be made only upon approval in the Commission's final decisions and orders in the Hawaiian Electric 2007 test year rate case and the Hawaiian Electric 2009 test year rate cases. HECO ST-22 at 5.

For settlement purposes, the Parties agreed to allocate any final increase in electric revenues to the proposed rate classes in the percentages shown below:

Schedule R	35.74%
Schedule G	4.48%
Schedule J	34.22%
Schedule DS	7.06%
Schedule P	17.86%
Schedule F	0.64%
Total	100.00%

Settlement Exhibit at 85.

The settlement considered the positions of Hawaiian Electric, the Consumer Advocate, and the Department of Defense on cost of service and movement of inter-class revenues towards the respective cost of service positions. Settlement Exhibit at 85.

2. RATE DESIGN

In its direct testimony, Hawaiian Electric proposed tiered residential rates (which were also proposed in Docket No. 2006-0386, Hawaiian Electric's test year 2007 rate case) to mitigate the rate impact on the smallest users of the system, to develop pricing signals that encourage conservation, and to assign a greater share of the cost increase to the largest users. In addition, Hawaiian Electric proposed to modify the residential time-of-use rate option, Schedule TOU-R to widen opportunities for residential customers to shift energy consumption to off-peak hours to create bill savings. HECO T-22 at 25. Hawaiian Electric proposed to create a separate rate class for customers who are directly served from a dedicated substation and to eliminate Schedule H, consistent with the settlement agreement in Docket No. 2006-0386. Hawaiian Electric also proposed to simplify commercial rate schedules by designing a single demand charge and a single energy charge for each rate schedule. HECO T-22 at 23.

In its direct testimony, the Consumer Advocate did not support Hawaiian Electric's proposed changes in the Schedule R customer charges and minimum charges. CA-T-5 at 41. The Consumer Advocate supported Hawaiian Electric's proposed changes in commercial rate structures, but recommended limiting the increase in Schedule J customer charges to 10% of existing rate levels (CA-T-5 at 44) and limiting demand charge increases to no more than 125% of the existing rate levels (CA-T-5 at 47).

In its direct testimony, the Department of Defense supported Hawaiian Electric's proposed rate schedules DS and P, although it disagreed with the amount of revenue assigned to these rate schedules (DOD-300, page 23).

For settlement purposes, the Parties agreed to the concepts and rate levels for overall rate design shown in Settlement Exhibit HECO T-22 Attachment 2.

In its Interim Decision and Order, the Commission found that the proposed Employee Discount in Schedule E may be unduly discriminatory and under-allocate electricity costs to Hawaiian Electric's employees and former employees. For purposes of interim rates, the commission directed Hawaiian Electric to remove Schedule E and adjust other rates based on this change. IDO at 11.

The Company provided supplemental testimony regarding the Employee Discount issue, and there was substantial oral testimony at the evidentiary hearing, as discussed in greater detail elsewhere in this Opening Brief.

Also in its Interim Decision and Order, the Commission found that Hawaiian Electric's proposed time of use rates merited additional examination prior to the final decision in this docket. Specifically, the Commission posed the following questions: 1) Are the time-of-use ("TOU") rates incorporated in rate design for the purpose of incenting off-peak use and dis-incenting on-peak use; 2) Is this the proper proceeding to consider TOU, or should it be more appropriately considered in the AMI docket; and 3) Can the State make progress toward energy efficiency through rate design without AMI? IDO at 13, 15.

In its supplemental testimony, Hawaiian Electric addressed the Commission's question whether the TOU rates are in the rate design for the purpose of incenting off-peak use and dis-incenting on-peak use. The TOU rates that are proposed in the rate design are proposed revisions to existing TOU rates that were approved in the Hawaiian Electric 2005 test year rate case. The TOU rates are rate options; they provide customers with an additional choice. Customers have the opportunity to participate in TOU rates to reduce their electric bills by shifting kW and kWh consumption to usage periods where the rate charged is lower. Such a shift in usage could be from priority peak hours to mid-peak hours, from priority peak hours to off-peak hours, from mid-peak hours to off-peak hours, or some combination of the three. HECO ST-22 at 6.

In response to the Commission's question regarding the appropriateness of considering TOU rates in this rate case proceeding rather than the AMI proceeding, the Company stated that the rate case proceeding is the proper venue to consider TOU and all other elements of rate design. It is particularly important to consider a TOU rate design option and its associated base rate design in the same proceeding in order to coordinate both rate proposals. The TOU rate proposals that are included in the AMI application in Docket No. 2008-0303 are the same TOU rate proposals that have been made in the open rate cases for the Hawaiian Electric Companies. HECO ST-22 at 6-7.

In response to the Commission's question regarding the State making progress toward energy efficiency through rate design without AMI, the Company presented testimony that Hawaiian Electric has already proposed rate design changes that promote energy efficiency. For example, in its 2007 test year rate case and its 2009 test year rate case, Hawaiian Electric has proposed inclining block rates for the residential service class. Also in the 2009 test year rate case, Hawaiian Electric has proposed a single demand charge rate for Schedule DS and Schedule P (which are the proposed rate schedules for existing Schedule PS, Schedule PP, and Schedule PT customers), replacing the declining block structure of the existing demand charges. In addition, greater alignment of class revenues with the class cost of service will promote energy efficiency. HECO ST-22 at 7.

<u>Service-Related Charges and Proposed Rule Change</u>

Hawaiian Electric proposed to increase its Returned Payment Charge from the current $16.00 to $22.00 per returned check or returned payment. This is the same proposal that Hawaiian Electric made in Docket No. 2006-0386, its test year 2007 rate case. The proposed Returned Payment Charge of $22.00 per returned payment is based on the 2003-2004 recorded costs of processing returned payments. It reflects the labor processing costs as well as the non-labor costs including bank charges at estimated 2005 levels. HECO T-22 at 50-51; HECO-WP-2219; HECO-106 at 2.

Hawaiian Electric did not propose to change other service-related charges included in the Company Rules that are charged directly to the customers who caused the costs to be incurred by the Company, such as the Field Collection Charge, Service Establishment Charge, and Late Payment Charge. HECO T-22 at 49.

Power Factor Cost Study

In its direct testimony, Hawaiian Electric performed a power factor study and concluded that the present power factor adjustment did not require modification. HECO T-22 at 52. The Consumer Advocate's position was that Hawaiian Electric's power factor study did not include all costs contributing to providing reactive power charges. The Consumer Advocate recommended that Hawaiian Electric be required to prepare a power factor study that includes generating unit, transmission, and distribution system costs associated with providing reactive power. CA-T-2 at 53-54. The Department of Defense's position was that Hawaiian Electric's study cannot be relied upon and no changes be made to power factor charges at this time. DOD-300 at 25.

For settlement purposes, the Parties agreed to the following: 1) the information provided in this docket is insufficient to establish a revised basis for the power factor rate adjustment; 2) the existing power factor provision shall be retained as proposed in Hawaiian Electric's proposed

Schedule J, Schedule P, Schedule DS, Schedule U, and Schedule TOU-J rate schedules; and 3) a working group comprised of representatives from all three (3) parties will be established to examine the issue of rate adjustment for power factor. As part of this examination the working group will review approaches taken in other jurisdictions and before other regulatory bodies in order to develop a revised approach to the pricing of Hawaiian Electric's power factor adjustment. The working group's finding and recommendations will be presented for adoption in Hawaiian Electric's next general rate case. Settlement Exhibit at 86.

Purchased Power Adjustment Clause

In its Rate Case Update, Hawaiian Electric proposed a Purchased Power Adjustment ("PPA") Clause pursuant to Section 30 of the HCEI Agreement. HECO T-1 Rate Case Update at 7-8; HECO T-22 Rate Case Update at 2-4. Because this provision called for the transfer of recovery of all capacity, O&M and other non-energy payments from base rates to a new surcharge, the Company stated that it was appropriate to propose the PPA Clause in this rate case. Purchased energy costs would continue to be recovered through the Energy Cost Adjustment Clause to the extent they are not recovered through base rates. Hawaiian Electric did not remove any purchased power costs from the test year revenue requirement but as shown in Attachment 1, page 36 of the HECO T-22 Rate Case Update, Hawaiian Electric included $175,431,000 of electric sales revenues at proposed rates for recovery through the new PPA Clause in the 2009 test year. HECO T-1 Rate Case Update at 8; HECO T-22 Rate Case Update at 2-4.

The Consumer Advocate stated that it was generally satisfied with the purpose of the clause and the manner that the clause will assess and pass through costs to customers. Since the Company indicated that the PPA Clause will be adjusted monthly and reconciled quarterly, the

Consumer Advocate recommended that Hawaiian Electric be required to file its calculations with the Commission at least quarterly and that such calculations be reviewed and approved by the Commission to ensure that customers are appropriately charged for projected purchased power costs. Furthermore, the Consumer Advocate recommended that Hawaiian Electric's filing include all necessary workpapers and supporting documentation that would allow the Commission and other parties to determine that Hawaiian Electric is not recovering purchased power non-energy costs more than once through the different cost recovery mechanisms beyond base rates that will be available to the Company. Settlement Exhibit at 87.

For purposes of settlement, the Company agreed to file its calculations (including workpapers and supporting documentation) with the Commission at least quarterly. However, because the PPA Clause would be an automatic cost adjustment clause and will be adjusted monthly, the Company proposed, and the Parties agreed, that explicit Commission approval of each PPA Clause filing will not be practicable nor required. Like other automatic adjustment clauses, the monthly PPA Clause adjustment can be allowed to go into effect at the first of each month, subject to the ability of the Commission to investigate and revise any adjustment and order the refund of any over-collection. Settlement Exhibit at 87.

Further, the Company agreed to request explicit approval to recover the non-energy costs associated with a purchased power agreement through the PPA clause, and will not recover such costs through the PPA Clause until the Commission has approved the associated purchased power agreement. The Company will also continue to execute fuel contracts on a long term basis where feasible and execute agreements for non-fossil fuel generation at rates that are de-linked from the price of fossil fuels, in accordance with Section 269-27.2 of the Hawaii Revised Statutes. This procurement strategy will have the effect of limited hedging. However, the

Company was at this time opposed to engaging in speculative fuel price hedging in an attempt to minimize its fuel costs for the reasons expressed in its *Report on Power Cost Adjustments and Hedging Fuel Risks* (HECO-1040). Settlement Exhibit at 87-88.

In its Interim Decision and Order, the Commission found that more information is needed to determine the reasonableness of the proposed PPAC. IDO at 14. In its supplemental testimony, the Company submitted additional testimony to support the reasonableness of the proposed PPAC, as is discussed in greater detail elsewhere in this Opening Brief. HECO ST-20 at 1–11.

Revenue Decoupling - Revenue Balancing Account

In its Rate Case Update, the Company proposed a revenue decoupling mechanism to be effective upon issuance of an interim decision and order in this Hawaiian Electric 2009 rate case. HECO T-1 Rate Case Update at 8-11.

Hawaiian Electric also submitted a proposed tariff in the response to CA-IR-277 in this rate case that would establish a revenue balancing account ("RBA") that would remove the linkage between electric revenues and sales, effective on the date of the interim decision and order. HECO T-22 Attachment 1 revised the RBA tariff to conform with agreements reached between the Consumer Advocate and the Hawaiian Electric Companies in the decoupling proceeding, as reflected in the Joint Final Statement of Position of the Hawaiian Electric Companies and the Consumer Advocate filed May 11, 2009 in Docket No. 2008-0274. This would implement the provision in paragraph 1 of Section 28 of the HCEI Agreement which states: "The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009)." The Company stated, however, that if the Commission does not accept the proposal to establish a revenue balancing account in this proceeding, Hawaiian Electric should be allowed to revise its 2009 test year estimates according to the sales forecast reduction. HECO T-1 Rate Case Update at 8-11.

The Joint Decoupling Proposal submitted by the Hawaiian Electric Companies and the Consumer Advocate in the decoupling proceeding includes a sales decoupling mechanism, which will be implemented through the RBA and a Revenue Adjustment Mechanism (or "RAM"). The proposal is to implement sales decoupling through the attached RBA tariff at the time of the interim increase. All parties in the decoupling docket appear to be in agreement that sales decoupling should be implemented. The RBA approved as part of the final decision would be conformed to the sales decoupling mechanism ultimately approved by the Commission in the decoupling docket. There is no proposal to implement the RAM as part of the interim rate changes approved by the Commission, and the RAM would not be implemented until the Commission concludes its review and approval process in the decoupling docket. Settlement Exhibit at 2.

Although the Consumer Advocate's testimonies did not address whether a revenue balancing account should be approved in this proceeding, the Consumer Advocate agreed in the decoupling proceeding (Docket No. 2008-0274) that "...the initial sales decoupling mechanism would begin with the establishment of Authorized Base Revenues, which would be equal to the revenue requirements approved by the Commission in its interim decision and orders for HECO's 2009 test year general rate case proceeding and MECO's and HELCO's 2009 or 2010 test year general rate case proceedings". Joint Final Statement of Position of the HECO Companies and Consumer Advocate at page 11; Settlement Exhibit at 2.

For purposes of settlement, the Parties agreed that the Commission should allow

Hawaiian Electric to establish a revenue balancing account as described in its Rate Case Updates to be effective on the date of the interim decision and order in this proceeding. Settlement Exhibit at 3.

In its Interim Decision and Order, the Commission stated that since the Commission has not yet determined that a sales decoupling mechanism and the establishment of Hawaiian Electric's proposed RBA are just and reasonable in the decoupling docket (Docket No. 2008-0274), the Commission disallowed any cost related to the implementation of the RBA at this time. IDO at 8.

On November 25, 2009, the Hawaiian Electric Companies filed a Motion for Interim Approval of a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company Limited, in the decoupling proceeding, Docket No. 2008-0274. The Motion requested interim approval of: (1) the establishment and implementation by Hawaiian Electric of the RBA, with a slight modification to include only one RBA account for all residential and nonresidential customers, to be effective January 1, 2010; (2) the establishment and implementation by Hawaiian Electric of the revenue adjustment mechanism ("RAM") to refund to ratepayers (with interest) RAM revenues associated with disallowed costs for Baseline Capital Projects, and to include an interim performance metric as described in the Memorandum in Support of Motion, to be effective beginning with calendar year 2010; (3) both the Hawaiian Electric RBA and RAM to remain in effect until interim rates become effective pursuant to an interim decision and order in Hawaiian Electric's 2011 test year rate case, provided that Hawaiian Electric does not file a 2010 test year rate case application, and files its 2011 test year rate case application by August 16, 2010; (4) implementation by HELCO and MECO of the RBA and RAM at such time as interim rates become effective pursuant to interim decision and orders in HELCO's and MECO's respective 2010 test year rate cases; and the continuation of this proceeding for the primary purpose of evaluating the design and potential adoption of clean energy-related decoupling performance metrics, with final statements of position to be filed by the parties no later than June 30, 2010. Motion for Interim Approval of a Decoupling Mechanism, Docket No. 2008-0274, at 1-3.

3. OTHER COST OF SERVICE AND RATE DESIGN ISSUES

1. Employee Electricity Rate Discount

In Section II.2(b) of the Interim Decision & Order, the Commission noted that the Company's Schedule E, HECO-106 at 24, supplied electricity to the Company's full-time employees and former employees at rates that were two-thirds of the effective Schedule R rate for the first 825 kWh of consumption each period. The Commission observed that such rates "may be unduly discriminatory and under-allocate electricity costs" to such individuals. For purposes of interim rates, the Commission directed the Company to remove Schedule E and to adjust other rates accordingly. It also invited the parties to supply additional testimony on the "justness and reasonableness" of Schedule E. ID&O at 11.

The Company promptly complied with the Commission's interim directive to remove Schedule E and adjust other rates as appropriate. CA-ST-1 at 5. With regard to the reasonableness of Schedule E, the Company filed the supplemental testimonies of (i) Robert A. Alm, Executive Vice President of the Company; (ii) Michael H. McInerny, Manager of the Company's Industrial Relations Department; and (iii) Julie K. Price, the Company's Manager of Compensation and Benefits. Mr. Alm noted that the main premise behind the Schedule E discount is to "compensate its employees with minimal tax consequences. Generally, it would cost more in additional salary and/or benefits to replace the discount." HECO ST-1 at 36. The discount is not included as taxable income to the employee, unlike pension benefits that are only tax-deferred until receipt. Also, if the discount were replaced with comparable wages or salaries, the replacement amount would have to be grossed up for individual income and employee withholding taxes to achieve comparable economic value. HECO response to PUC-IR-156. As a whole, the Company would need to spend an estimated $1,163,641 to replace the economic value of the discount to active employees; this would exceed the cost of the estimated 2009 test year discount by $478,691. HECO response to PUC-IR-157; see also Tr. (Vol. II) at 339-41 (Furuta-Okayama and Alm). Providing the Schedule E discount is thus reasonable in that it provides a benefit to employees in a very cost-efficient manner, relative to conferring such value in the form of wages and salaries.

Moreover, the discount is reasonable in that it abides by Hawaii corporate standards and aligns with employee discounts previously approved by the Commission. Mr. Alm noted in his supplemental testimony that "[i]t is commonly known that many companies in Hawaii provide some form of employee discounts." HECO ST-1 at 36-37. Mr. Alm also cited two Commission decisions in support of discounts. In In Re Hawaiian Electric. Co., Docket No. 3705, Decision and Order No. 6275 (July 9, 1980), at 15, the Commission specifically found that:

> The comparative analysis of HECO's employees and residential customers other than HECO's employees, made by the Consumer Advocate was insufficient for the Commission to conclude that in fact HECO's employees were not energy oriented in their consumption of electricity .... The Consumer Advocate had the burden of showing that the employee discount was unreasonable for the reasons it stated. There was inconclusive evidence on the part of the Consumer Advocate on this issue. If in fact, any future studies do show that the employees are wasteful in their energy use due to the discount, the Commission can reconsider this issue.

In Docket No. 6432, Decision and Order No. 10993 (March 6, 1991), at 154, the Commission stated:

> Employee discount has been an issue many times before. The commission has repeatedly

> rejected its elimination. We will adhere to our past decisions and reject its elimination in this docket. The employee discount has been negotiated in good faith between [Hawaii Electric Light Company, Inc.] and its employees. We are constrained from interfering with that agreement, although there is nothing that legally requires us to recognize the discount.

See HECO ST-1 at 37. The Commission has clearly expressed a strong desire, time and again, to uphold discounts "negotiated in good faith" between the Company and its employees. The discount was negotiated between the Company and the IBEW and included in the Collective Bargaining Agreement. HECO ST-1 at 37-38; HECO ST-15B at 5-6; HECO ST-13 at 9. It follows that the discount should be deemed a reasonable contractual arrangement and approved by the Commission, in accordance with the Commission's prior decisions.

Additionally, at the Panel Evidentiary Hearing, Mr. Alm responded to questions regarding the discount's seeming inconsistency with the Company's policy of reducing Hawaii's dependence on electricity. Mr. Alm first noted that the Schedule E discount "cap" of 825 kWh was instituted to avoid excessive use of energy by the beneficiaries of the discount. He also stated his belief that the discount, as structured, does not result in excessive electricity usage by employees because they are "well aware of the overall desire to cut use," and they "hear it and work with it more than probably any other citizens in the community because it's part of our job." Tr. (Vol. II) at 325, 327 (Alm). Exact information on the difference in average consumption, if any, between discount recipients and non-recipients was unavailable at the time of the hearing. See Tr. (Vol. II) at 337-39 (Young, Furuta-Okayama and Alm) (observing that a seemingly large difference in per customer usage between the Company's employee and retiree population and the residential population as a whole was based on incomplete data and required "further analysis"). A subsequent hearing exhibit does show a difference in 2008 between general consumers under Schedule R, who had an average monthly usage of 654 kWh and a median monthly usage of 537 kWh, and consumers under discounted Schedule E, with an average of 813 kWh and a median of 727 kWh. HECO Hearing Exhibit 13. However, the hearing exhibit does not account for differences in average and median household size between Schedule R and Schedule E consumers, nor does it track consumption over a span of years (2008 may have been an anomalous period). If Mr. Alm's view of consumption under Schedule E is correct, it supports a finding that the discount does not conflict with the Company's mission to reduce electricity usage and is therefore reasonable.

Because the Schedule E discount confers considerable cost savings, follows Hawaii company standards, is supported by Commission precedent and may be consistent with the Company's energy conservation policy, it should be retained as a very reasonable benefit for the Company's employees.[113]

4. ENERGY COST ADJUSTMENT CLAUSE

1. Introduction

The Energy Cost Adjustment Clause ("ECAC") is an automatic adjustment provision in the utility's rate schedules that allows the utility, without a rate proceeding, to automatically increase or decrease charges to reflect changes in the Company's energy costs of fuel and purchased energy above or below the levels included in the base charges. The Company's current base fuel energy charges and central station fixed efficiency factor embedded in the base charges, shown in HECO-1034, were established in HECO's 2005 Test Year rate case, Docket

[113] Notwithstanding the preceding analysis, if the Commission were to go against its prior decisions and choose to terminate Schedule E, the Company respectfully requests that the termination apply to all discount recipients and be done prospectively – that is, after the Collective Bargaining Agreement, which includes Schedule E as an agreed-upon provision, has expired. Mr. Alm cited three cases, across three jurisdictions, in support of delaying termination. HECO ST-1 at 38. Mr. Alm also noted at the Panel Evidentiary Hearing that the IBEW believes it is entitled to the discount irrespective of the discount's termination by the Commission, and intends to take the matter to arbitration. Maintaining Schedule E through the term of the Collective Bargaining Agreement would help avoid further tension between the Company and the IBEW. Tr. (Vol. II) at 346-48, 353-54 (Alm, McInerny).

No. 04-0113. HECO T-10 at 62.

The purpose of ECAC is: (1) to address price changes in the Company's cost of fuel and purchased energy; and (2) to accommodate changes to the actual mix of generation, utility-DG (distributed generation) and purchased energy resources, without the need for a rate case. HECO T-10 at 63.

The ECAC works as follows: A rate case proceeding determines the base electricity rates which are predicated on test year levels of fuel prices, payment rates for purchased energy, and resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover costs due to subsequent changes in: (1) fuel and purchased energy costs; (2) the resource mix between utility-owned generation, utility-DG and purchased energy; (3) the resource mix among the central station utility plants and utility-DG; and (4) the resource mix among purchased energy producers. A rate case proceeding also established a fixed efficiency factor(s), or sales heat rate(s), for the utility central station generation units to encourage efficient operation of the system units. An ECA Factor, which sets the rate adjustment that reflects these changes for the coming month, is filed with the Commission monthly. HECO T-10 at 63.

The following costs are currently passed through the ECAC: The Company's fuel oil, trucking, and fuel related costs associated with its central station units, diesel fuel and trucking costs associated with its utility-DG units, and its purchased energy costs pass through the ECAC. The low sulfur fuel oil (LSFO) and diesel fuel oil costs in the central station units and diesel fuel oil costs in the utility-DG units are discussed by Mr. Sakuda (HECO T-4) and Mr. Cox (HECO T-5). Fuel related costs that currently pass through the ECAC include fuel inspection costs (referred to as Petrospect expenses) and trucking costs for the central station Honolulu units and utility-DG units. Payments for purchased energy, but not capacity costs, are passed through the

ECAC. HECO T-10 at 64.

With respect to Kalaeloa and AES Hawaii, for both current and proposed rates, only the fuel and fuel additive components of Kalaeloa's energy charge and the fuel component of AES Hawaii's energy charge are included in the ECAC. HECO T-10 at 64.

The Distributed Generation ("DG") component will allow ratepayers to benefit from the improved efficiency resulting from the installation of utility-owned DGs. HECO expects that additional utility-owned or operated DG units will be installed in the near future (e.g., distributed standby generation at the Honolulu Airport). Furthermore, the efficiency of utility-owned DG units is better than the efficiency of the utility's central station units (see HECO-404). Therefore, as additional DG units are added to the HECO system over time, the system efficiency may improve. Including the existing utility-owned DG units in the ECAC fixed efficiency factor would not allow ratepayers to benefit from improvement in the efficiency factor expected when additional utility-owned or operated DG units come on-line because the ECAC fixed efficiency factor is not adjusted until the next rate proceeding. HECO T-10 at 64-65.

On the other hand, a separate DG component recovers DG fuel and transportation costs at actual expense levels and would not be subject to a fixed efficiency factor. Thus, to the extent that the added DG unit efficiencies are better than the fixed efficiency factor, the separate DG component will pass the impact of improved efficiency through the ECAC to ratepayers. HECO T-10 at 65.

At present rates, the fuel additives costs are not being passed through the ECAC. However, the Company is proposing to pass through the fuel additive costs for Kahe 6 unit in ECAC at proposed rates. Since additives may also be injected into other HECO generating units, HECO is proposing that the cost of additives, when used in other generating units, would also be passed through the ECAC. HECO T-10 at 66.

The recovery of the fuel additive in the ECAC was approved in HECO's test year 2007 rate case, Docket No. 2006-0386. On October 22, 2007, the Company received from the Commission, Interim D&O No. 23749 for HECO's 2007 test year rate case. The 2007 test year estimate of fuel additive costs is included in the determination of the Company's 2007 test year interim increase. Since the 2007 test year interim rates are included in the estimate of revenue at current effective rates, the recovery of fuel additives is included in that estimate. HECO T-10 at 66-67.

The Company added new fuel price and btu mix line items in the central station generation component section of the ECAC calculations for CIP CT-1, as shown in HECO-1037, page 1. While CIP CT-1 is burning regular diesel fuel, the fuel price will be the price of diesel. If by the time CIP CT-1 begins burning biodiesel fuel and approval to include biodiesel contract and fuel costs has not been received from the Commission, the fuel price for biodiesel will be zero in the monthly ECAC filings. Whether CIP CT-1 is burning diesel or biodiesel, the weighted fuel cost will be included in the monthly determination of the central station composite cost of generation. HECO T-10 at 67-68.

The Company is proposing to include a weighted efficiency factor in its ECAC calculations in its central station generation component, in the same manner as was introduced in Docket No. 05-0315, Hawaii Electric Light Company, Inc. (HELCO) 2006 test year rate case; Docket No. 2006-0387; Maui Electric Company, Limited (MECO) 2007 test year rate case; and in Docket No. 2006-0386, HECO 2007 test year rate case. These dockets are pending before the Commission. As discussed in these dockets, the proposed weighted efficiency factor addresses the diversity of fuel burned in the central station generating units. HECO T-10 at 69.

The fixed efficiency factors for LSFO, diesel, and biodiesel burning central station generating units are determined from the production simulation. The efficiency factor for each of the three generating unit types is weighted by the MWh contribution of each type to the total central station MWh generation. HECO T-10 at 69.

Biodiesel fuel is added as a fuel type in determining the weighted efficiency factor because the CIP CT-1 unit is anticipated to burn biodiesel in 2009. HECO T-10 at 69.

At HELCO, another efficiency factor was derived for Company-owned renewable generating units (wind and hydro at HELCO). While HECO does not currently own any renewable generating units, a fourth "Other" efficiency factor has been derived and included in HECO's proposed ECA clause for consistency. HECO T-10 at 69.

The avoided energy cost rates and Schedule Q rates are determined using the QF In/QF Out methodology approved by the Commission in Docket No. 7310. The Company will replace the previous proxy method calculations with the QF In/QF Out method approved in Docket No.7310. HECO T-10 at 69-70.

The Company's position is that the ECAC structure for HECO, HELCO, and MECO should be identical. Uniformity across the utilities' ECACs reduces the administrative costs for all Parties. Treating the fuel and purchased energy cost recovery of one utility differently from another would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs. HECO T-10 at 75.

Heat Rate Deadband Proposal

In the Decoupling Docket, the joint proposal of the Hawaiian Electric Companies

(HECO, HELCO and MECO, collectively) and the Consumer Advocate[114] included a provision to establish a heat rate deadband around the fixed heat rate that is based on a weighted efficiency factor (determined by the mix percentages of central station fuel type) within which there is a complete pass-through of fuel and purchased energy expenses. This allows the utilities to more accurately recover their fixed costs under sales decoupling (when within the range of the upper and lower heat rate deadband).[115]

Hawaiian Electric proposes in this rate case that the generation efficiency factors determined herein be the target heat rates around which the deadbands would apply. The proposed deadband is +/- 50 Btu/kwh sales.

In addition, the Hawaiian Electric Companies and the Consumer Advocate jointly proposed provisions to allow the target heat rate (around which the deadband would apply) to be reset under various circumstances. The Joint Statement of Position includes provisions to allow the target heat rate (around which the deadband would apply) to be reset under various circumstances. Paragraph C.1.c. on page 4 of the Joint Statement of Position of the HECO Companies and the Consumer Advocate, Revised and New Exhibits, filed on June 25, 2009 in this proceeding, stated that the target heat rates "should be subject to adjustments if additions, retirements or modifications to their generating systems, or modifications to their generating system operating procedures, are expected to increase or decrease the target heat rates by more than the deadband amounts." Therefore, if Hawaiian Electric expects that addition of a new renewable as-available resource or that additions, retirements or modifications to its generating

[114] See Joint Final Statement of Position of the HECO Companies and Consumer Advocate filed May 11, 2009, Exhibit D, in Docket No. 2008-0274. For a detailed discussion on the proposal on HELCO's sales heat rate deadbands, please refer to the Joint Statement of Position, Revised and New Exhibits, filed on June 25, 2009 in Docket No. 2008-0274, Exhibit C, Attachment 7, Section C, pages 3 to 6.

[115] The record in the decoupling docket supporting the heat rate deadband was incorporated by reference in this proceeding.

system will cause its target heat rates to fall outside of the proposed deadband, Hawaiian Electric will seek to revise the target heat rates before its next rate case, i.e., after the rate case in the instant docket and before next rate case after this docket. The proposal to change the heat rate target outside of the 2009 test year should be evaluated as part of the instant docket. The proposed change to the target heat rate should take effect when Hawaiian Electric begins purchasing energy from the new renewable as-available resource or when additions, retirements or modifications to its generating system are in service. This would be consistent with the Hawaiian Electric Companies-Consumer Advocate joint proposal, dated June 25, 2009, in Docket No. 2008-0274, in Exhibit C, Attachment 7, paragraph C.3.b. on page 5.

2. Need for and Benefits of ECAC

The Company needs the ECAC because fuel costs are a large portion of its expenses and because fuel price levels are largely beyond the Company's control. HECO T-10 at 65.

In the test year, fuel and purchased energy expenses make up about 74% of total O&M expenses. This makes the Company's financial condition very sensitive to changes in fuel prices. The ECAC benefits the Company and its shareholders by:[116]

(1) Limiting the swings in cash flow and earnings,

(2) Reducing the cost of capital,

(3) Improving the Company's ability to earn a fair return on investor capital, and;

(4) Providing a more timely recovery of fuel and purchased energy costs.

The ECAC benefits customers by:[117]

> (1) Reducing the Company's financial risk and lowering the cost of capital. The resulting savings are passed on to customers through lower base rates in rate proceedings such as this one.

(2) Passing through to customers, savings incurred when fuel prices fall below the

[116] HECO T-10 at 65.
[117] HECO T-10 at 66.

prices embedded in base rates, to the same extent that they will incur additional costs when fuel prices are above the embedded fuel prices.

Other Jurisdictions

In general, FACs are designed to reduce regulatory costs by separating the volatile fuel, purchased energy, and distributed energy costs from the rate proceedings. A prime motivation for FACs is a reduction in general rate cases. The reduction of frequent general rate cases does not reduce the Commission's oversight of HECO's fuel and purchased energy expenditures. Electric FACs allow for recovery of carefully-defined categories of fossil fuel costs, nuclear fuel costs, purchased energy, fuel transportation costs, and hedging costs, among others. Calculations supporting the ECAC are submitted to the Commission for review on a monthly basis. HECO ST-10B at 24-25.

FAC mechanisms (and other cost-adjustment mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases—called "regulatory lag"—can increase. The three classic reasons for a FAC include:

(1) The purchased item (most commonly fuel) is outside the control of the buying utility.

(2) The item is a significant or large component of the utility's total operating costs.

(3) The cost changes with respect to that item can be volatile and unpredictable.

It is not necessary that individual cost items be large, volatile and unpredictable to qualify for FAC treatment. An effective FAC covers all purchased energy costs, including renewable sources, on an equal footing. HECO ST-10B at 26.

According to Dr. Makholm, Hawaiian Electric's ECAC compares well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery. HECO ST-10B at 6, 25-32.

FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah lacks a FAC. Many states have instituted state-wide FAC mechanisms available to all electric (or gas) utilities. Some states have dealt with each utility on a case-by-case basis, which has led to inconsistencies across utilities within these states regarding power cost adjustments. HECO ST-10B at 31. Nearly every state regulatory commission has ruled in favor of the FAC. Many states that previously revoked their FAC have reinstated in recent years. HECO ST-10B (page 32, Figure 4) lists the states that have recently reinstated an FAC for an electric utility in the state.

Financial Integrity

The design of the current ECAC mechanism preserves, to the extent reasonably possible, the public utility's financial integrity. The current ECAC mechanism is a strength in HECO's business risk profile and contributes to the Company's financial integrity. The monthly timeliness of the existing ECAC also minimizes the recovery time period, further reducing investor uncertainty with respect to recovery of fuel costs. S&P has often cited the existing ECAC mechanism as a strength in HECO's credit quality assessment. HECO T-20 at 31-32.

HECO's investors view the Company's existing ECAC mechanism very favorably, because it significantly reduces the risks associated with HECO's business. Dependence on imported fuel oil and the associated fuel price fluctuation are significant risks in HECO's business. The monthly revenue adjustment for fuel and purchased energy price changes results in timely recovery of fuel oil and purchased energy costs, which significantly reduces the business risk profile. Thus, the existing ECAC has a positive credit quality impact. HECO T-20 at 28.

The presence of an ECAC also is viewed favorably by rating agencies. S&P stated in November 2002 its opinion concerning the importance of electric utilities having the opportunity to recover fuel and purchased power expenses:

> When assessing the importance of productive regulation to the credit strength of an electric utility, something to consider is the means by which the utility can expect to recover variable expenses, particularly fuel and purchased-power expenses, which have highly erratic unit costs. Recent, and in some cases, extreme volatility in the U.S. wholesale electricity markets, as well as in the natural gas markets, underscores this importance. It is no coincidence that utilities with stronger fuel and power cost recovery mechanisms typically enjoy loftier credit ratings.

Conversely, the absence of an ECAC would be viewed very negatively by rating agencies.[118]

In its credit assessment of HECO, S&P has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality, and in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality. HECO T-20 at 28.

There have been recent changes in investor concerns relating to the Company's fuel and purchased power expenses. In 2006, Act 162 (discussed below) required that the Commission evaluate the continued use of ECAC in each rate proceeding in which it was requested by the Company. The Company's investors are clearly concerned by the legislative action. In its credit assessment of HECO dated May 23, 2008, S&P cites the existing ECAC as a major rating factor strength, but then further cites any potential change to the existing ECAC as a major rating factor weakness:[119]

[118] HECO T-21 at 21-23, quoting S&P Research: "Constructive Regulation for U.S. Utilities Is More Important Than Ever," November 14, 2002 (provided in Attachment 4 to CA-IR-23); Moody's Global Credit Research: "Rating Methodology: Global Regulated Electric Utilities," March 2005 (provided in Attachment 3 to CA-IR-23); Fitch Special Report: "Electric Fuels Outlook: The Fuels Dilemma," November 11, 2004 (provided in Attachment 5 to CA-IR-23); Fitch Special Report: "U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery," February 13, 2006 (provided in Attachment 6 to CA-IR-23); Fitch Special Report: "Cost Recovery and Public Power: Who Is at Risk?," June 1, 2006 (provided in Attachment 7 to CA-IR-23).

[119] HECO T-20 at 27 .

"The current ECAC design is under consideration by the Hawaii Public Utilities Commission ('PUC') in all three of HECO's pending utility rate cases; a material change to the ECAC could harm the company's financial condition." and

"Actions that weaken the ECAC's ability to protect utility credit quality would be of concern."

There are other investor risks associated with fuel and purchased power. As explained in HECO T-20 at 33-44, the Company has significant power purchase obligations (e.g., the Company expects to purchase approximately 42% of its energy from IPPs) which are considered in evaluations of the Company's credit. The reliance on purchased power creates debt-like obligations, which are of concern to investors. Further, there have been changes in the accounting treatment of the power purchase obligations and there is uncertainty as to how these changes may impact investor views of these obligations. HECO T-20 at 28.

Second, the Company is exposed to financial variability due to changes in fuel efficiency. In a rate case proceeding, fuel expense is established based on fuel efficiency factors, which are embedded in base electric rates. Mr. Sakuda provides a complete description of the fuel efficiency calculation in HECO T-4. When actual heat rates are lower (better) than the heat rates embedded in base rates, fuel expense is lower and returns to shareholders are higher. When actual heat rates are higher (worse) than the heat rates embedded in base rates, fuel expense is higher and returns to shareholders are lower. This gives management incentive to optimize the generation dispatch and to maintain and operate the company-owned generation to maximize fuel efficiency. HECO T-20 at 28-29.

Finally, the Company bears the costs or enjoys the benefits from cost savings resulting from changes in the carrying costs of fuel inventory. The cost of fuel inventory fluctuates as fuel prices fluctuate. Higher fuel prices result in higher inventory cost and higher costs of carrying inventory which reduce returns to shareholders. Conversely, lower fuel prices result in lower inventory cost and lower costs of carrying inventory which contribute to shareholder returns. There is not much near-term management control over these carrying costs since inventory volumes are constrained by operational requirements and inventory price is determined by fuel prices indexed to world oil prices embedded in long-term fuel purchase contracts. However, since the absolute amounts of inventory carrying costs are relatively small; this risk is not viewed as a significant business risk from an investor's perspective. HECO T-20 at 29.

3. Compliance with Act 162

On June 2, 2006, the Governor of Hawaii signed into law Act 162, Session Laws of Hawaii 2006, which states "any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:

> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
>
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;
>
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
>
> (4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
>
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

HECO's ECAC complies with Act 162. As explained in HECO T-10, Hawaiian Electric and HELCO retained the services of Dr. Jeff D. Makholm, a Senior Vice President at National Economic Research Associates, Inc. ("NERA"), who provided testimony in the HECO 2007 test year rate case (Docket No. 2006-0386) and the HELCO 2006 test year rate case (Docket No. 05-0315) explaining the role of fuel adjustment clauses ("FACs") in utility ratemaking in the United States, and addressing the compliance of HECO's ECAC with Act 162. Mr. Makholm concluded that (1) FACs are a standard and longstanding part of U.S. utility ratemaking, (2) HECO's ECAC is a well-designed FAC and benefits HECO and its ratepayers, and (3) HECO's ECAC complies with the statutory requirements of Act 162.

In testimony in the same proceedings, Mr. Eugene T. Meehan, who also is a Senior Vice President at NERA, provided a summary in of the type of fuel price hedging that potentially could be performed by HECO in the marketplace and an assessment of the potential impacts of fuel price hedging on HECO, its customers and the regulatory ratemaking process. His conclusions with respect to fuel price hedging include:[120]

> (1) Hedging of oil by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs,
>
> (2) The liquidity of standard financial hedging products with a term of over a year is limited, and while HECO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so,
>
> (3) It would not be reasonable for HECO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses, and
>
> (4) Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal, and there is no compelling reason for HECO to use fuel price hedging as the means to achieving the objective of increased rate stability.

On December 29, 2006, the Companies filed the consultant's final report, Report on Power Cost Adjustments and Hedging Fuel Risks, (see HECO-1040) with the Commission.

Interim D&O

In the Commission's Interim Decision and Order filed July 2, 2009 in this instant docket,

[120] HECO T-10 at .

the Commission indicated it desires additional testimony regarding whether Hawaiian Electric's proposed ECAC complies with the statutory requirements of HRS § 269-16(g) (Interim Decision and Order at 14 to15). As a result, Hawaiian Electric asked Dr. Makholm to provide testimony in this docket explaining the role of fuel adjustment clauses in utility ratemaking in the United States, to address the compliance of Hawaiian Electric's current power cost recovery mechanism, the ECAC, with the applicable statute, and to assess the potential impacts of fuel price hedging on HECO, its customers, and the regulatory ratemaking process. HECO ST-10B at 3-4.

First Requirement of Act 162

The first requirement of Act 162 addresses whether the ECAC fairly shares the risk of fuel cost changes between the utility and its customers. The risk of fuel cost changes comprises two things:[121]

> (1) Changes in the *price* of fuel as a single productive input; and,
>
> (2) Changes in the *cost* to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn purchased fuel into electricity, which may require HECO to purchase a greater *quantity* of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Fair sharing of the risk of changes in the *price* of fuel as a productive input occurs when the utility has the means to control a cost and it has a corresponding incentive to do so (*i.e.*, it shares the risk associated with that cost). It is not economically efficient to impose risk of cost recovery on the utility when the utility is not able to control the cost. This distinction is critical because the *price* of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact. HECO ST-10B at 7-8.

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[121] HECO ST-10B at 7.

In a price-taking market, such as the fuel markets for Hawaiian Electric, imposing price change risks on the utility would lead to no efficiency gains resulting from management incentives to minimize costs. Passing such costs through to customers supports the utility's ability to maintain its financial viability, and it would increase regulatory lag—the time between rate cases—for costs that *are* within the utility's control, which would enhance the utility's incentive to control its base rate costs. HECO ST-10B at 8. The risk of changes in the cost to deliver and produce electricity from HECO's fuel inputs can be described as follows:

The ECAC, with its "heat rate" efficiency factor (which may change to a heat rate deadband approach as jointly proposed by the Hawaiian Electric Companies and the Consumer Advocate in Docket No. 2008-0274), provides a partial pass-through of fuel costs. It shares the costs and/or benefits of decreased or increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has some managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel, purchased energy, and distributed energy.

This heat rate efficiency factor assigns the risk of changes in the cost to deliver and produce electricity from HECO's fuel inputs to HECO's management, while allowing changes in the price of fuel to be passed through to ratepayers. HECO ST-10B at 9.

Under the existing ECAC, customers generally bear the risk of fuel price changes and shareholders generally bear the risk of fuel efficiency changes. Customers pay less when actual fuel prices decline, and customers pay more when actual fuel prices escalate. In establishing a fair rate of return on equity, the Company's current ECAC is assumed to continue (see HECO T-19). The concept that shareholders do not make any profit from fuel price changes is therefore embedded in the return on equity recommendation. This is "fair" because shareholders do not require compensation for risks that they do not bear. HECO T-20 at 30.

Partial Pass-Through

HECO maintains that partial pass-through of fuel and purchased energy costs is not a viable option for Hawaii. Partial pass-through mechanisms and their impact on utility financial health were discussed in a study conducted by NERA in a *Report on Power Cost Adjustments and Hedging Fuel Risks* that was forwarded to the Commission in Docket No. 2006-0386 (HECO's 2007 Test Year Rate Case) on December 29, 2006. In that study, NERA concluded:[122]

> (1) Some states, e.g., Arizona, Colorado, Idaho, and Washington, have adopted partial pass-through mechanisms. These are sometimes referred to as "risk sharing" mechanisms. However, this characterization is incorrect because the utility is a price taker and has no control over the price of fuel in the global market place. (Page 26)
>
> (2) These partial pass-through states actually represent a broad movement towards less risk imposed on the utilities. For example, Idaho Power had been subject to a zero pass-through and moved toward a 90% pass-through. (Page 27)
>
> (3) Oil generally plays an insignificant role in these utilities' generation mix. These utilities typically get most of their power from hydro, nuclear, and coal. (Page 28)
>
> (4) "Fuel prices constitute a large and volatile cost for price taking utilities. A well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Partial pass through mechanisms that defer power cost recovery in an attempt to shield ratepayers from power cost changes present an inefficient solution to the rate stability issues and the rising cost of electricity input costs. Forcing a utility to temporarily absorb a portion of power cost changes (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) does not prevent consumers from ultimately having to pay the full amount for their power usage, and may harm the utility's financial position." (Page 29)

The NERA report concluded that, "Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over

[122] HECO T-10 at 76-77.

world oil markets." HECO T-10 at 77, citing page 30.

In addition, in March 2008 HECO requested NERA to conduct a survey of all 50 states and the District of Columbia to determine to what extent FAC mechanisms were used in the United States. The survey found that 33 traditionally regulated states incorporate FAC mechanisms into their regulation of electric utilities. Of those 33 states, 22 states allow 100% pass through of fuel and power costs (including Hawaii, which is subject to an energy efficiency factor), as shown in HECO-1041. Thus, Hawaii is not the only state which allows full pass-through of fuel and purchased energy costs. HECO T-10 at 77-78.

Eighteen states (including the District of Columbia) do not have FAC mechanisms. Adjustment clauses in 15 of those 18 states are not applicable because the utilities there are typically restructured, distribution-only, utilities that do not have their own generation. Thus, those utilities do not need a FAC. These distribution-only utilities pass on the full cost of generation to customers in the cost of the electricity that the customers purchase from producers. Two additional states, Nebraska and Alaska, are public power states where there are no investor-owned utilities. Finally, Utah is an investor-owned utility, that has not restructured, that does not have a FAC. It recovers its fuel costs through temporary rate increases. HECO T-10 at 78.

Of the 33 states that have FACs, 22 states have 100% pass-through of fuel and power costs. The FACs in the remaining 11 states utilize some form of dead-bands, sharing, or caps on fuel cost pass-through. The primary source of fuel in these states is either coal or hydro[123]. Coal is generally secured under long-term contracts and exhibit less volatility than oil or natural gas. Hydroelectric power has low marginal costs. Thus, in those states using primarily coal or hydro, the change in costs of generation are low relative to states that use oil or natural gas. Therefore,

[123] The exception is Arizona, which has a mix of coal, nuclear, and natural gas.

100% pass-through does not have the financial significance in those states that it does in Hawaii. HECO T-10 at 78.

Limiting the pass-through in the change in the cost of power to 80%, 90%, or 95% would decrease HECO's test year 2009 ECA revenues at current effective rates by approximately $110,600,000, $55,300,000, or $27,600,000, respectively, as shown in HECO-1042. Had the limitation been in effect it would have resulted in severe financial hardship for the utility. HECO T-10 at 78-79.

If the existing ECAC were to be modified to include 80%, 90%, or 95% of the fuel and purchased energy costs, the impact on renewable energy development would also be adverse. The financial strength of the utility as the off-taker of IPP renewable energy is a critical criterion that supports financing of renewable energy projects. The presence of the ECAC contributes significantly to the financial strength of the Company, which in turn makes finding financing by renewable energy developers more likely. If the ECAC was changed from a full pass-through to a partial pass-through mechanism, the financial health of the Company would be undermined and this would make financing for renewable energy projects in the state more difficult. HECO T-20 at 32-33.

As Dr. Makholm pointed out, if a utility only partially recovers its power costs through its FAC, investors will require a higher return on their capital to reflect the riskier investment.[124] While a partial pass-through of power costs may initially reduce the level of rates when unexpected fuel price increases occur, it may ultimately lead to higher costs to consumers. HECO ST-10B at 10.

In addition to financial impacts, a partial pass-through would not send an accurate and

[124] A utility's cost of equity is set based on a comparable group. Nearly all utilities have cost-recovery mechanisms in place.

correct price signal to customers. Sending an accurate and correct price signal to reflect 100% of the true cost of fuel would allow customers to make appropriate decisions regarding their energy efficiency and conservation behavior, which could lead to lower energy use. HECO T-10 at 79; HECO ST-10B at 10.

Second Requirement of Act 162

The second condition required by Act 162 requires that automatic rate adjustment mechanisms be designed to "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy." This condition is closely tied to the previous one. HECO's targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs. HECO ST-10B at 10.

All purchases of fuel and electricity (renewable and non-renewable) should be on an equal footing. The ECAC should cover all purchased energy costs, including renewable and distributed generation sources, on an equal footing within the cost recovery mechanism.

Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. HECO ST-10B at 11-12. As Mr. Alm testified, there is no indication that the ECAC discourages the use of renewable energy:[125]

> (1) HECO and its sister utilities are already moving aggressively on renewable activities. They already have significant renewables on their systems (HPOWER, HC&S, PGV, HRD, KWP) and new projects are on the way, especially in the area of wind. As the Consumer Advocate indicated in its Statements of Position filed on November 8, 2004 in Docket Nos. 04-0128 and 04-0129, HECO's "use of the ECAC to address the changing price of fuel does not appear to have diminished its effort in research and utilization of renewable energy."
>
> (2) The current ECAC allows the Companies to bring on new as-available renewable purchase power agreements without rate proceedings, including those with prices that are de-linked from the price of oil. Thus, a major potential

[125] HECO T-1 at 98-99, citing Docket No. 04-0113, Tr. (9/16/05) at 48.

> disincentive to the Companies has been removed, because they can immediately pass on the costs of renewable projects. Firm renewable projects can be added without a rate case due to the availability of the firm capacity surcharge for nonfossil fuel producers, plus the ECAC.
>
> (3) Instead of changing the ECAC to change how the Companies view oil, and to encourage them to seek more renewables, it makes sense to look at incentives that will encourage utilities to engage in renewable activities, which is exactly what the Renewable Energy Infrastructure Program proposed by the Company in Docket No. 2007-0416 attempts to do, without causing major harm to the financial health of the Company.

A frequently updated and well designed FAC mechanism would support renewable resource development. The ECAC has positive implications on a utility's financial integrity and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. The ECAC allows utilities to recover renewable energy expenses in a timely manner, subject to Commission oversight, without waiting for a rate case. Because the utility may serve as a counter-party for renewable energy developers, the credit standing of a utility frequently serves as an important determinant of renewable energy projects' ability to raise capital, and thus, improve reliability and resource diversity. Weakening the utility's credit rating through partial power cost recovery could harm renewable energy projects that rely on utility counter-party credit to support their investments. Thus, the ECAC is a useful and timely mechanism to accommodating increased amounts of renewable energy. HECO ST-10B at 12.

Ratepayers will not necessarily choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity, and a timely FAC therefore has an important role to play in transmitting these price signals. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they may reduce their demand when the price outweighs the benefit of consuming the product.

Dr. Makholm concluded that, so long as the ECAC treats all sources of generation equally and allows the recovery of energy costs from all sources, it complies with this condition.

HECO ST-10B at 13.

Third Requirement of Act 162

The third requirement established in Act 16 requires "the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

Hedging of oil by HECO would not be expected to reduce fuel and purchased energy costs and in fact would be expected to increase the level of such costs. In other words: "There are no free lunches in risk management." Hedging has real costs to the party that wishes to reduce its exposure to price movements. In some years, ratepayers may benefit from a price hedge as prices rise, but in times when prices do not rise or fall, this will not be the case. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased energy expenses. Accordingly, if there is a mandate for the utility to reduce ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers. While the Company works hard to procure fuel at the lowest possible cost, HECO does not have any meaningful control over the fundamental market conditions affecting fuel cost increases and market volatility. HECO ST-10B at 14.

Factors that prevent HECO from undertaking a hedging program include:[126]

> (1) Hedging involves cost and these costs are in addition to the cost to acquire the fuel. Customers can expect to pay more on average if HECO is mandated to adopt a hedging strategy, which in turn increases the predictability of fuel prices which may not be perceived as beneficial by all customers.
>
> (2) Hedging is imperfect. Perfect hedges can only be accomplished when the hedged asset is identical to the acquired asset and when the volume to be acquired is certain. This would pose basis risk if HECO could not buy financial instruments that correspond exactly to the product. Basis risk is the difference in the price movement between the derivative used to hedge and the price movement of the underlying asset. It is my understanding that there are no market-traded hedging

[126] HECO ST-10B at 14-15.

instruments for Singapore low sulfur waxy residual ("LSWR"), which is the market index used to price the low sulfur fuel oil used by the Company. HECO's customers would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. For HECO's customers, the basis risk is substantial because both the indices in HECO's oil contracts and the available derivatives are not traded in the most liquid and transparent derivative markets.

Billing Alternatives

There are alternatives to price risk hedging available that can provide similar rate smoothing benefits, such as budget billing plans and fixed rate plans. HECO ST-10B at 16, 19.

Budget billing is an optional payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limit any negative consumer feedback and target the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year. At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan. Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers. HECO ST-10B at 16-17.

In response to PUC-IR-108.b, Hawaiian Electric stated that:

(1) The benefit to customers from budget billing is that some customers (e.g., those on fixed incomes) would benefit from predictability of the monthly energy bill, which would help those particular customers to mitigate the effects of volatile changes in monthly energy costs. The voluntary nature of these programs limits negative consumer feedback and targets the program to the consumers that want them. With the effective extension of the payment horizon for the full cost of consumed energy over the course of a year, consumers could be better able to plan their finances.

(2) The disadvantage of budget billing is that "At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan." (HECO ST-10B at 17.) The amount of true-up would not be known to the customer until it is billed at the end of the year. The size of the true-up depends on the usage and electricity price used to estimate the fixed bill that the customer would pay for that year. Depending on how the estimated usage and electricity price compared to the actual usage and electricity price during the year, the true-up could be either an additional payment or a credit on the customer's next bill after the end of the year. For example, if the customer's actual annual usage was greater than the estimate and/or if the actual electricity prices were higher than the estimate due to an increase in fuel prices, the true-up could be positive and the customer would have to pay his normal electricity bill, plus pay the true-up. A different relationship between the estimates and actuals could result in the true-up being a credit to the bill and reduce it below the normal electricity bill amount.

(3) If the customer does not know what the true-up amount is, it will be difficult for the customer to anticipate the amount he/she will need to pay for the bill that follows the end of the year. If the true-up amount is a large payment due, say to increasing fuel prices, the customer may find himself/herself in a difficult financial position. This could have an adverse effect on bad debts to the Company.

(4) Hawaiian Electric proposes to submit for Commission review within 12 months from the date of the Commission's final decision and order in the instant docket, a pilot budget billing program for its review. As is the case for HELCO, the schedule for actual implementation of the HECO pilot depends on the in-service date for the new CIS.

Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays a fixed rate per kWh with no reconciliation, but with a risk premium. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases. HECO ST-10B at 17.

The risk premium is necessary because fixed rate billing presents risks and additional costs to the utility. If fuel and purchased energy prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, customers electing a fixed rate billing option may force the utility to hedge against a position in the market for the underlying oil commodity. If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, they would be effectively speculating on the fuel markets. HECO ST-10B at 17.

In Hawaiian Electric's view, it could not engage in fixed rate billing without hedging. See response to PUC-IR-135.

The risk premium would need to be large enough to compensate the utility for any added risks and costs on average, but during periods of rising fuel prices, a large group of ratepayers taking out a fixed rate may affect a utility's liquidity and its financial health. HECO ST-10B at 18.

Regarding the ECAC's compliance with the third condition of Act 162, there is no compelling reason for HECO to use fuel price hedging. There is no particular business reason for HECO to hedge and the benefits to customers are unclear. Even if rate smoothing were to be a desired policy goal, there likely are more effective means of meeting the goal. HECO ST-10B at 18.

If fuel hedging were to be implemented, fuel hedging objectives would need to be developed in close consultation with regulators and customers and approved a priori as hedging by HECO on behalf of customers and not for HECO's shareholders account. If HECO were to implement fuel hedging it should be well understood that the Company would not be expected to speculate by attempting to time the market to minimize oil purchase costs. HECO ST-10B at 19. Fuel (oil) hedging by HECO will be expected to result in increased customer costs and as such should only be seriously considered if there is a countervailing benefit. HECO ST-10B at 18.

Fourth Requirement of Act 162

The fourth requirement of Act 162is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity." For modern utilities that operate in a world of volatile fuel prices, a FAC is critical to:[127]

> (1) Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.
>
> (2) Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
>
> (3) Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating.[128] Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms. Exhibit HECO-S-10B01 presents a selection of statements from the three major credit rating agencies detailing the critical role of power cost recovery in their credit rating evaluation process.
>
> (4) Maintain HECO's ability to raise capital. Because oil, and other fuel expenses, are a large portion of HECO's operational costs [ ], the ECAC is necessary because it allows HECO to raise capital at a reasonable cost in good markets and bad.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. A FAC helps to ensure that a utility has a sufficient opportunity to earn a fair return on equity, and is needed to help the Company maintain its overall financial health so that it can effectively compete for the capital it needs in good markets and bad, particularly given that nearly all similarly situated utilities have implemented FACs. HECO ST-10B at 21-22, <u>citing</u> regulatory commission decisions in Colorado, Arizona and Missouri.

<u>Fifth Requirement of Act 162</u>

The fifth requirement established by Act 162 is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for

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[127] HECO ST-10B at 20-21.

[128] Again, most of any particular utility's peers also have a FAC and therefore a lack of a FAC would increase a utility's risk relative to its peers.

the changes to its fuel costs."

In general, FACs are designed to reduce regulatory costs by separating the volatile fuel, purchased energy, and distributed energy costs from the rate proceedings. A prime motivation for FACs is a reduction in general rate cases. The reduction of frequent general rate cases does not reduce the Commission's oversight of HECO's fuel and purchased energy expenditures. Electric FACs allow for recovery of carefully-defined categories of fossil fuel costs, nuclear fuel costs, purchased energy, fuel transportation costs, and hedging costs, among others. Calculations supporting the ECAC are submitted to the Commission for review on a monthly basis. HECO ST-10B at 24-25.

4. <u>ECA Factor</u>

In its direct testimony, the Company calculated an Energy Cost Adjustment Factor ("ECAF") of 7.221 cents per kWh at current effective rates and at present rates and an ECAF of 0.000 cents per kWh at proposed rates for the 2009 test year (HECO-1033). The changes in the Company's fuel oil and fuel related inspection costs, trucking costs, and purchased energy costs from the total fuel costs embedded in base rates are recovered through the ECAC. The Company proposed to include the recovery of changes in fuel additive costs through the ECAC (fuel additive costs are proposed to be embedded in base rates) and to include a weighted efficiency factor (sales heat rate) in its ECAC calculations (in the same manner as HELCO proposed in Docket No. 05-0315, MECO proposed in Docket No. 2006-0387 and HECO proposed in Docket No. 2006-0386), based on fixed efficiency factors for LSFO, diesel, biodiesel and "other" generating units. Because DG units are generally more efficient than other generating units, the Company proposed not to apply a fixed efficiency factor to DG fuel and transportation costs (HECO T-10, page 69). The Company proposed the following efficiency factors at proposed rates in its direct testimony (HECO-1037):[129]

LSFO:	0.011092 mbtu/kwh
Diesel:	0.024358 mbtu/kwh
Biodiesel:	0.022909 mbtu/kwh
Other plants:	0.011185 mbtu/kwh
Weighted average:	0.011185 mbtu/kwh

The updated sales estimates necessitated a new production simulation run to develop updated fuel and purchased energy estimates. Rate Case Update (rev. December 8, 2008), HECO T-10 at 11. The updated ECAF's at present and proposed rates were shown in the revised HECO-1033 on page 20. Calculations for the ECAF at present rates were shown in the revised HECO-1036 on page 21. Calculations for the ECAF at proposed rates were shown in the revised HECO-1037 on pages 22-23. The weighted central station efficiency factor calculations were also updated and were shown in the revised HECO-1039 on page 28.

In CA-T-1, the Consumer Advocate did not object to the continuation of the ECAC to provide HECO with full recovery of changes in energy costs (CA-T-1 pages 51 to 52). In CA-T-2, the Consumer Advocate calculated an ECAF of 0.571 cents per kWh at current effective rates based on its production simulation results for the 2009 test year which incorporated the September 2008 sales forecast reduction and December 2008 fuel prices as described above. The DOD did not object to HECO's ECAC proposals (DOD-300, page 26). Settlement Agreement, Exhibit 1 at 16.

HECO agreed with certain production simulation assumptions proposed by the Consumer Advocate but proposed to use a December 2008 fuel price for Kalaeloa. HECO recalculated the ECAF based on the lower sales forecast and December 2008 fuel prices (including Kalaeloa). The resulting ECAF was 0.152 cents per kWh at current effective and present rates which when

[129] Settlement Agreement, Exhibit 1 at 15.

applied to 7,484.7 gWh yielded ECAC revenues of $11,376,800 at current effective and present rates as shown in HECO T-3, Attachment 1, page 1, column B. The ECAF at proposed rates was 0.000 cents per kWh. Settlement Agreement, Exhibit 1 at ; see Final Settlement, HECO T-10, Attachment 1, page 1.

The Consumer Advocate acknowledged that HECO's recalculated ECAFs were reasonable and accepted them for purposes of setting rates in this proceeding. Settlement Agreement, Exhibit 1 at 16.

In the Settlement Agreement, the Parties agreed that the ECAF at current effective and present rates is 0.152 cents per kWh, 0.000 cents per kWh at proposed rates, and the sales heat rates used in the ECAF as fixed efficiency factors at proposed rates are:[130]

LSFO:	0.011114 mbtu/kwh
Diesel:	0.024582 mbtu/kwh
Biodiesel:	0.016762 mbtu/kwh
Other plants:	0.011184 mbtu/kwh
Weighted average:	0.011184 mbtu/kwh

5. Conclusion

In HECO ST-10B, Dr. Makholm concluded that: "Fuel prices constitute a large and volatile cost for price-taking utilities. A well-established, frequently-updated FAC is essential to maintain a utility's credit and operational viability and thereby meet the requirements of customers." HECO ST-10B at 32.

In HECO T-19, Dr. Roger Morin, HECO's expert witness on the cost of common equity, explained that consideration of energy costs in a manner that lowers uncertainty and risk "represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect

[130] Settlement Agreement, Exhibit 1 at 16. See HECO T-10, Attachment 1, page 9, Final Settlement.

investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed." HECO T-19 at 57-58.

As Dr. Morin also states, "it is my understanding" that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element, which in turn would raise its cost of capital. HECO T-19 at 58.

Dr. Morin adds that the "approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become widespread. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy." HECO T-19 at 58.

Dr. Morin concludes that, in the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, HECO's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO. This situation would have a substantial effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service. HECO T-19 at 58.

In HECO T-21, Mr. Steven Fetter, a former Chairman of the Michigan Public Service Commission and former Managing Director and Group Head at the credit rating agency Fitch, Inc., states that the existence of an ECAC is a key factor for investors, and discontinuation or limitation on the scope or timeliness of such mechanism would place HECO at a competitive disadvantage in attracting capital in the current economic environment. He also points out the following:

> (1) The presence of an ECAC is the predominant policy position among regulatory bodies across the U.S. This is especially true within the states operating under a traditional cost of service regulatory framework.
>
> (2) Consideration of fuel costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Thus, the financial community takes the presence of an ECAC as virtually a given when comparing utilities across jurisdictions for possible investment.

Thus, Mr. Fetter concludes that --

> it is crucial that the Commission allow HECO to continue to use an ECAC. ECACs attempt to align the costs that a utility expends for fuel and purchased power with its recovery of those costs on a timely basis. By being able to recover prudently incurred costs expeditiously, a utility lowers the risk of its operations and achieves consistency with the level of risk faced by a wide majority of other utilities within the United States, all of which are chasing the same investor funds. It is wholly consistent with rational utility economics for customers to pay the actual costs of fuel and purchased power that are procured for customers' benefit, whether those costs are in an escalating mode or actually going down.

HECO T-21 at 28.

5. PURCHASED POWER ADJUSTMENT CLAUSE

1. Proposal for a PPAC

In its Rate Case Update (HECO T-1, pages 7 to 8), HECO proposed a Purchased Power Adjustment Clause ("PPAC") pursuant to Section 30 of the Energy Agreement, which calls for the transfer of recovery of all capacity, O&M and other non-energy payments from base rates to a new surcharge. Purchased energy costs would continue to be recovered through the ECAC to the extent they are not recovered through base rates. Hawaiian Electric did not remove any purchased power costs from the test year revenue requirement but as shown in Attachment 1, page 36 of the HECO T-22 Rate Case Update, HECO included $175,431,000 of electric sales revenues at proposed rates for recovery through the new PPAC in the 2009 test year. Settlement

Agreement, Exhibit 1 at 89; HECO RT-20 at 19.

The Energy Agreement includes the following provision in Section 30:

- The Hawaiian Electric Companies will be allowed to pass through reasonably incurred purchase power contract costs, including all capacity, O&M and other non-energy payments approved by the Commission (including those acquired under the feed-in tariff) through a separate surcharge.
- If approved, these costs will be moved from base rates to the new surcharge.
- The surcharge will be adjusted monthly and reconciled quarterly.

The Consumer Advocate stated that it was generally satisfied with the purpose of the clause and the manner that the clause will assess and pass through costs to customers. Since the Company indicated that the PPAC will be adjusted monthly and reconciled quarterly, the Consumer Advocate recommended that Hawaiian Electric be required to file its calculations with the Commission at least quarterly and that such calculations be reviewed and approved by the Commission to ensure that customers are appropriately charged for projected purchased power costs. Furthermore, the Consumer Advocate recommended that Hawaiian Electric's filing include all necessary workpapers and supporting documentation that would allow the Commission and other parties to determine that Hawaiian Electric is not recovering purchased power non-energy costs more than once through the different cost recovery mechanisms beyond base rates that will be available to the Company. Settlement Agreement, Exhibit 1 at 89.

2. Benefits of the PPAC

Hawaiian Electric pointed out the potential benefits of a PPAC in its direct testimonies,[131]

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[131] See HECO T-20 at 34-41. The Interim D&O stated that: "In its update to HECO T-22, HECO has proposed the PPAC pursuant to Section 30 of the Energy Agreement. The commission finds, however, that more information is needed to determine the reasonableness of this surcharge." Interim D&O at 14. Accordingly, in HECO ST-20, Hawaiian Electric identified the substantial evidence already in the record supporting the reasonableness of the PPAC, including (1) Rate Case Update, HECO T-22, (2) HECO T-

which were filed before negotiation and execution to the Energy Agreement, as well as in its rate case updates and supplemental testimonies.

The purpose of the purchased power adjustment clause is to enhance the Company's financial profile, and to maintain HECO's current credit rating, which should help enable Hawaiin Electric support new Hawaii Clean Energy Initiatives. A financially stable utility will be able to invest in new renewable resources and infrastructure to facilitate the addition of new renewable resources from independent power producers, to convert the existing system to renewable technologies. See Rate Case Update, HECO T-20, at 1. In addition, renewable purchased power development will be promoted, because a company with a strong credit rating is more likely to attract renewable resource developers than a company with a weak credit rating. A creditworthy off-taker helps to attract prospective independent power producers. See HECO RT-20, at 20. Also, enhancing the Company's financial profile and maintaining its credit rating will enable Hawaiian Electric to support new clean energy initiatives under the Energy Agreement. See HECO ST-20 at 4; Rate Case Update, HECO T-20 at 1; HECO T-20 Update (December 23, 2008).

S&P calculates the imputed debt for PPAs by taking the present value of the total fixed payments over the life of the contracts, using the company's average cost of debt as the discount rate (6%) for the present value calculation.[132] It then determines a risk factor to apply to the

20, pages 13 to 17, 22 to 23, 33 to 41, and 48 to 50, (3) HECO-2016, (4) Rate Case Update, HECO T-1, pages 7 to 8, (5) Rate Case Update, HECO T-20, pages 1 to 6, and Attachment 1, (6) HECO RT-1, pages 32 to 33, (7) HECO RT-20, pages 18 to 21, (8) HECO-R-2007, (9) HECO-RWP-2007, and (10) Company's responses to CA-IR-380; DOD-IR-133; DOD-RIR-9; and DOD RIR-21.

[132] Other credit rating agencies also consider the impacts of power purchase obligations; however, the Company utilizes the S&P methodology because S&P is most transparent on methodology they employ. S&P published its original PPA criteria in 1991, and provided updates in 1993, 2003 and 2007. S&P "Buy versus Build: Debt Aspects of Purchased-Power Agreements" dated May 8, 2003 was filed as HECO-2111 in Docket No. 04-0113, S&P "Request for Comments: Imputing Debt to Purchased Power Obligations" dated November 1, 2006 was filed as HECO-1915 in Docket No. 2006-0386, and S&P Ratings Direct "Standard & Poor's Methodology for Imputing Debt for U.S.

contract to reflect the riskiness to the utility based on the terms of the contract and assurances of cost recovery. In its credit assessment of HECO dated May 23, 2008[133], S&P assigned a risk factor of 50% to HECO's firm capacity power purchase contracts.[134] The risk factor is applied to the present value of the fixed payments under the contract to calculate the imputed debt.[135] HECO T-20 at 34- 35, citting S&P Ratings Direct "Standard & Poor's Methodology of Imputing Debt for U.S. Utilities' Power Purchase Agreements" dated May 7, 2007 filed as HECO-2013.

As a result of the imputed debt, HECO has increased the proportion of equity in its capital structure. This increases the overall cost of capital and increases the revenue requirement. HECO T-20 at 35.

Recovery of all purchased power costs through a purchase power cost recovery mechanism should not negatively impact customers. Purchased power energy costs currently are recovered through ECAC, which would not change. Purchased power capacity and operations & maintenance costs are generally stable costs, and there should not be any significant or immediate rate impact on customers from the transfer of recovery of all capacity, O&M and other non-energy payments from base rates to a new surcharge. HECO RT-20 at 20-21; see response to PUC-IR-128.

Based on discussions with S&P, the use of a purchased power cost recovery mechanism may reduce S&P's risk factor for the Company's power purchase agreements from 50% to

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Utilities' Power Purchase Agreements" dated May 7, 2007 filed in response to DOD-IR-68 in Docket No. 2006-0386. HECO T-20 at 34 n.26.

[133] See S&P Ratings Direct "Hawaiian Electric Co. Inc." dated May 23, 2008 filed as HECO-2008.

[134] The risk factor is 50% even though ratepayers are bearing all the purchased power costs. Although the purchased power costs have been allowed in all rate cases, S&P makes it clear that where purchased power costs are evaluated in each general rate case, the rating agency believes that recovery is at risk in each rate case. Since they view that recovery is at risk in each rate case, it leads the agency to assign the 50% risk factor. Further, although purchased power energy costs are currently recovered through base rates and the ECAC, other purchased power costs (for capacity and O&M) are recovered in base rates only. HECO T-20 at 37.

[135] HECO T-20 at 34.

25%.[136] The reduction in risk factor would reduce the imputed debt. The reduction in imputed debt could be used to: (1) improve credit quality or (2) increase the proportions of debt in the Company's capital structure, or (3) some combination of the two. HECO T-20 at 37-38, 49; HECO RT-20 at 20.

Customers would benefit from approval of the PPAC, if the PPAC results in a lower imputed debt. In order to continue to provide customers with reliable electric service, the Company foresees increasing needs for capital investment to maintain the reliability of the existing system as well as to support renewable energy development. To raise the necessary capital to make these investments, the Company needs access to the capital markets to be able to tap financial resources when needed for such capital investments. Alternative recovery mechanisms, such as a PPAC that helps to align cost incurrence with cost recovery, are supportive of credit quality and may facilitate raising capital at a reasonable cost.

In the longer term, customers could potentially benefit from approval of the PPAC, if the PPAC results in a lower imputed debt, through decreased interest rates and/or increased debt proportions (and lower common equity proportions) in Hawaiian Electric's capital structure. Lower interest rates and more debt/less common equity will result in a lower weighted cost of capital, a lower rate of return on rate base, and, ultimately, lower rates. HECO ST-20 at 6-7; HECO RT-20, at 21. More debt and less common equity in the Company's capital structure lowers the cost of capital, because the cost of debt is lower than the cost of common equity. HECO T-20 at 38, 50.

The reduction in imputed debt would improve HECO's financial ratios as viewed by S&P or can create room to accept more imputed debt from renewable PPAs, or some

[136] Recovery though a cost recovery mechanism will reduce the cost recovery risk, but will not eliminate it, since there would always be a risk of future changes to a recovery mechanism.

combination of the two. HECO T-20 Update (December 23, 2008). HECO anticipates increases in its actual debt as well as imputed debt as a result of numerous pending and contemplated long-term arrangements. See HECO RT-20 at 19. A decrease in imputed debt resulting from a decrease in S&P's risk factor assignment to purchased power may allow the Company to accommodate the anticipated increase in actual debt and imputed debt without degrading its financial profile and existing credit quality. HECO T-20 Update (December 23, 2008).

In summary, although the implementation of a purchased power adjustment clause is expected to improve the Company's credit quality, it is not expect to result in a credit rating improvement. Rather, the improvement in credit quality will help the Company to maintain its existing credit rating. HECO T-20 Update (December 23, 2008).

3. Circumstances Now Warrant a PPAC

The Company has proposed a purchased power cost recovery mechanism in the past. In HECO's 1994 test year rate case (Docket No. 7700), HECO requested recovery through a purchased power non-fuel adjustment clause. HECO's request was denied in D&O 13718 dated January 5, 1995. In denying the purchased power non-fuel adjustment clause, the Commission stated: "The proposed clause promotes single-issue ratemaking. Single-issue ratemaking does not account for potential changes in other cost items that may affect the relationship between costs and the returns earned by the company. An increase in certain purchased power costs may well be offset by increased productivity within HECO's own operations or by increased sales. Moreover, the automatic adjustment clause would not allow the commission to review such relationships. Rather, rates would rise merely because of a rise in a particular expense, without consideration of possible savings in other areas of the company's own operations."[137]

Since the Commission's rejection of the purchased power non-fuel adjustment clause in 1995, circumstances have changed. The benefits to ratepayers of assuming the risks of the purchased power costs via a purchased power cost recovery mechanism may now outweigh the issue of single-issue ratemaking and the need for ongoing review of the contracts. Since 1995, the PPAs have been shown to be prudent. Whereas in the early 1990's, the Company had just recently entered into its PPAs, so the need for continuing evaluation of the agreements may have been warranted. The major contracts are now over halfway through the contract terms and have proven to be prudent and reasonable. HECO T-20 at 40.

In contrast, the negative impact on credit quality has grown over the years. In the 1995 test year rate case (Docket No. 7766), HECO estimated an average test year imputed debt of $179 million. In this test year, HECO estimates an average test year imputed debt of $431 million for the same three PPAs. This increase in imputed debt theoretically costs ratepayers approximately $16 million in annual revenue requirement (all other things, including rate of return on equity, being constant). The imputed debt increase is attributable to the change in S&P's view of imputed debt rather than changes in the power purchase agreements. Had there been no change in S&P's imputed debt methodology, purchased power imputed debt would have decreased because the remaining contract obligation declines over time. S&P imputes more debt now than ever before, which negatively impacts the Company's financial risk profile and credit quality. HECO T-20 at 40-41.

4. Other Jurisdictions

Other electric utilities have adjustment clauses that permit them to recover PPA firm

[137] Order No. 13718 dated January 5, 1995 in Docket No. 7700.

capacity costs between rate cases. For example, Arizona Public Service, Empire District Electric Company (Oklahoma), Florida Power & Light Company, and Gulf Power (Florida) have automatic adjustment clauses to recover PPA capacity payments. AmerenUE (Missouri) has a fuel adjustment clause that permits the recovery of capacity charges for power purchase contracts of one year or less. In addition, Potomac Electric Power Company had a fuel clause in the District of Columbia that included firm capacity cost recovery prior to retail competition beginning in 1995. HECO ST-20 at 10.

The risk factor for at least some of the utilities with PPACs has been adjusted downwards. One example in which a mechanism was implemented that resulted in mitigating imputed debt is in the State of Vermont. In October 2008, the Vermont Public Service Board approved a Central Vermont Public Service ("CVPS") alternative regulation plan to better link customer and investor interests, improve efficiency and help control costs. The plan provides for, among other things, automatically adjusting rates on a quarterly basis to reflect fluctuating power purchase prices. In light of CVPS' implementation of the quarterly power cost adjustment mechanism in January 2009, Standard & Poor's ("S&P") reduced its risk factor associated with CVPS' power purchase agreements to 25% from 50%, thus mitigating the company's imputed debt. Response to PUC-IR-114.

It is Hawaiian Electric Company's understanding from communications with Florida Power & Light Co. ("FPL") that FPL is assigned a 25% risk factor by S&P. However, the only documentation that Hawaiian Electric Company has is S&P's RatingsDirect article dated April 1, 2005, which states a 30% risk factor being assigned to FPL. Response to PUC-IR-114.

5. PPAC Mechanism

For purposes of settlement, the Company agrees to file its calculations (including workpapers and supporting documentation) with the Commission at least quarterly. However, because the PPA Clause would be an automatic cost adjustment clause and will be adjusted monthly, the Company proposed, and the Parties agreed, that explicit Commission approval of each PPA Clause filing will not be practicable nor required. Like other automatic adjustment clauses, the monthly PPA Clause adjustment can be allowed to go into effect at the first of each month, subject to the ability of the Commission to investigate and revise any adjustment and order the refund of any over-collection. Settlement Agreement, Exhibit 1 at 89.

Further, the Company will request explicit approval to recover the non-energy costs associated with a purchased power agreement through the PPA clause, and will not recover such costs through the PPA Clause until the Commission has approved the associated purchased power agreement. The Company will also continue to execute fuel contracts on a long term basis where feasible and execute agreements for non-fossil fuel generation at rates that are de-linked from the price of fossil fuels, in accordance with Section 269-27.2 of the Hawaii Revised Statutes. This procurement strategy will have the effect of limited hedging. However, the Company is at this time opposed to engaging in speculative fuel price hedging in an attempt to minimize its fuel costs for the reasons expressed in its Report on Power Cost Adjustments and Hedging Fuel Risks (HECO-1040). Settlement Agreement, Exhibit 1 at 89-90; response to PUC-IR-127.

O **REGULATORY MATTERS**

1. **MANAGEMENT AUDIT**

The Commission's Interim D&O identified a possible management audit as one of several issues meriting additional examination prior to the final decision in this docket. IDO at 13. The Commission recognized that, "HECO app[ea]rs to be assuming that the revenue requirements approved prior to this rate case continue to be prudent and reasonable, and that it is taking advantage of all potential efficiencies." IDO at 16. The Commission therefore indicated that it was "considering ordering a management audit of the HECO Companies to evaluate whether this assumption is correct," and allowed the Parties to file additional testimony "*provid[ing] recommendations on the best way to engage in a management audit to be paid for* by HECO, or to suggest other means to accomplish the commission's objective." IDO at 16.

On October 12, 2009, the Commission identified the management audit as one of the issues that would be covered in its panel hearing. Letter from Commission to Parties dated October 12, 2009. The panel hearing on the management audit, Panel 11, was held on October 30, 2009. Tr. (Vol. V) at 793-865 (Brosch, Alm, Sekimura).

B. The Consumer Advocate Recommended a Focused Audit

The Consumer Advocate's witness, Michael L. Brosch, responded to the Commission's request to submit testimony regarding the management audit issue. Mr. Brosch indicated that his experiences with management audits have "generally been negative," with report recommendations "identify[ing] areas of relative management strength or weakness . . . rather than specific recommendations and/or adjustments that are useful in reaching regulatory decisions." CA-ST-1 at 11; Tr. (Vol. V) at 845-47 (Brosch). Mr. Brosch's experience is that "the most useful management audits are those aimed at solving specific problems that are important to the determination of just and reasonable rates." CA-ST-1 at 12. Mr. Brosch therefore suggested focused regulatory audits regarding the following issues: (a) CT-1 construction cost reasonableness; (b) East Oahu Transmission project construction cost reasonableness (upon completion); (c) CIS Project cost reasonableness (upon completion); (d) HECO Companies' productivity analysis (if used in an approved RAM); (e) HECO Companies' effectiveness in meeting HCEI performance obligations (for 2011 rate case); and (f) Periodic (ongoing) Financial Attest Audits to confirm accuracy and present any issues arising from existing and proposed surcharge filings of each regulated utility, including ECAC, PPAC, IRP/DSM; and RBA/RAM. Mr. Brosch also recommended focused management audits regarding the following process issues within HECO: (a) Technology (AMI and CIS) enabled TOU and other Pricing Initiatives; (b) Process issues to efficiently implement CESP filing and review; and (c) Capital projects management, cost control and accounting processes.

CA-ST-1 at 13; CA Hearing Exhibit 4; Tr. (Vol. V) at 836-844 (Brosch).

C. Existing Company Audits have or will Examine the Focused Topics Suggested by the Consumer Advocate

The Company does a detailed review in a rate case and the Company is proposing to have periodic rate cases in the Company's decoupling proposal. Although this does not equate to a formal management audit, the Company conducts a number of third-party reviews and broader reviews. Tr. (Vol. V) at 794-97 and 864-65 (Alm).

In addition, HECO has in the past been subject to third-party operational audits of specific projects, processes or divisions, and provided provided copies of reports from these audits. HECO's responses to PUC-IR-191, to PUC-1R-190 and to PUC-IR-171; Tr. (Vol. V) at 853-55 (Sekimura); HECO T-11 at 19-21.

Regarding review of the cost of CT-1, the Company has already provided a detailed cost report in Docket No. 05-0145, and in this rate case, the Company detailed its costs and support in testimony and responses to information requests. HECO ST-17A; HECO-S-17A02. The Company is also discussing a review of its capital project costing and estimation, presumably using CT-1 as an example. The goal of such a review would be to provide better estimates for both internal decision-making as well as for use by the Commission, the Consumer Advocate, and other parties to rate case proceedings. Tr. (Vol. V) at 856-57 (Alm).

Regarding the CIS project cost, the Company will be looking at the cost of that throughout. The IT governance area, one of the key issues, was actually reviewed, and the Company has already taken steps to improve and change IT governance. Attachment 10 to Hawaiian Electric's responses PUC-IR-171. Therefore, a portion of the CIS-related issues has already been examined at and has resulted in some changes in the Company. The Company also expects to continue to have reviews of how its IT area runs. Tr. (Vol. V) at 858 (Alm).

O **CONCLUSION**

Based on the evidence and authorities summarized in this Opening Brief, the motion for a second interim increase, and the entire record herein, Hawaiian Electric respectfully requests that the Commission (1) approve the Company's requested general increase in rates, as adjusted pursuant to the Settlement Agreement and the Results of Operations section of this brief, and (2) approve the changes in rates and rules requested in this proceeding.

DATED: Honolulu, Hawaii, January 5, 2010.

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.

EXHIBIT A

PROCEDURAL BACKGROUND

On May 1, 2008, Hawaiian Electric Company, Inc. ("Hawaiian Electric or HECO") filed a Notice of Intent, pursuant to Hawaii Administrative Rules ("HAR") § 6-61-85, stating that it planned to request rate relief based on a 2009 calendar year test period and file an application on or after July 1, 2008.

On July 3, 2008, Hawaiian Electric filed an application in Docket No. 2008-0083 for approval of rate increases and revised rate schedules and rules ("Application") in which Hawaiian Electric requested a general rate increase of approximately $97,011,000, or 5.2%, over revenues at current effective rates.[1] Hawaiian Electric's filing included its Direct Testimonies, Exhibits and Workpapers.

Hawaiian Electric served copies of the Application on the Division Of Consumer Advocacy, Department Of Commerce And Consumer Affairs ("Consumer Advocate"), an ex officio party to this docket, pursuant to HRS § 269-51 and HAR § 6-61-62.

By Order Granting Intervention to Department of Defense, filed on August 20, 2008, the Commission granted the Motion to Intervene and Become a Party of the Department Of The Navy on behalf of the Department Of Defense ("DOD") filed July 29, 2008.

On September 18, 2008, the Commission held a pubic hearing at the Commission Hearing Room in Honolulu to gather public comments on this docket.

[1] Revenues at current effective rates are revenues from base rates, revenues from the energy cost adjustment clause ("ECAC") and revenues from the interim rate increase that went into effect on November 1, 2008 in Hawaiian Electric's 2007 test year rate case, Docket No. 2006-0386.

On October 31, 2008, the Commission issued an Order[2] denying: (1) Motion to Intervene and Become a Party filed by Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Wal-Mart") on August 20, 2008;[3] (2) Motion to Intervene and Become a Party filed by Wal-Mart on September 2, 2008; (3) Motion to Intervene and Become a Party filed by the Hawaii Commercial Energy Customer Group ("Commercial Group") on September 29, 2008;[4] and (4) Commercial Group's Motion for Leave to File Reply to HECO's Memorandum in Opposition to Commercial Group's Intervention Motion, filed on October 21, 2008. In addition, the Commission found Hawaiian Electric's application to be complete and properly filed under HRS § 269-16(d) and HAR § 6-61-87, ordered that the filing date of Hawaiian Electric's application is July 3, 2008, and directed Hawaiian Electric, the Consumer Advocate, and the DOD (collectively, the "Parties") to submit to the Commission a stipulated procedural order by December 2, 2008.

In November and December 2008, Hawaiian Electric submitted voluminous updates to its 2009 test year estimates ("Rate Case Updates") set forth in the Application,

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[2] See Order Denying Motions to Intervene and Motion for Leave to File a Reply; Dismissing as Moot Motions to Appear and Motion for Enlargement of Time; Ruling on the Completeness of HECO's Application; and Directing the Parties to File a Stipulated Procedural Order Within Thirty Days.

[3] On August 20, 2008, Wal-Mart filed a Motion to Intervene in this docket. On August 27, 2008, Hawaiian Electric filed a Memorandum in Opposition to Wal-Mart's motion. On September 2, 2008, Wal-Mart filed a Notice of Withdrawal without prejudice of Motion to Intervene. On September 2, 2008, Wal-Mart filed a second Motion to Intervene in this docket.

[4] On September 29, 2008, the Commercial Group filed a Motion to Intervene in this docket. On October 1, 2008, Wal-Mart filed a Notice of Withdrawal and of its participation through the Commercial Group. On October 7, 2008, Hawaiian Electric filed a Memorandum in Opposition to the Commercial Group's motion. On October 21, 2008, the Commercial Group filed a Motion for Leave to File Reply to Hawaiian Electric's Memorandum in Opposition to the Commercial Group's Motion to Intervene. On November 12, 2008, Wal-Mart filed a Motion for Reconsideration of the Commission's October 31, 2008 order. By Order Denying Motion for Reconsideration and Dismissing as Moot Motion for Leave to File Reply, issued December 31, 2008, the Commission denied Wal-Mart's Motion for Reconsideration, and dismissed as moot the Motion for Leave to File a Reply to Wal-Mart's Reconsideration, filed by Hawaiian Electric on November 19, 2008.

Direct Testimonies, Exhibits, and Workpapers.[5] The Rate Case Updates included information on many of the pending, but not yet approved, HCEI-related programs currently before the Commission.

On January 12, 2009, the Commission issued, sua sponte, an Order Extending Date of Completeness of Application, extending the filing date of Hawaiian Electric's Application from July 3, 2008 to December 26, 2008. The Order indicated that Hawaiian Electric submitted voluminous updates to its Direct Testimonies in support of the Application that contained significant substantive changes to Hawaiian Electric's Direct Testimonies. To give the other Parties and the Commission sufficient time to review the updated Application, the Commission extended the filing date of Hawaiian Electric's completed Application to December 26, 2008, the date the last update was filed by Hawaiian Electric.

By letter filed January 13, 2009, Hawaiian Electric requested a one-week extension for the Parties to file a stipulated procedural order.[6]

Pursuant to the Stipulated Procedural Order, Hawaiian Electric responded to information requests ("IRs") submitted by the Consumer Advocate and the DOD during the period from July through October 2009. (Certain additional IR responses were provided to the Consumer Advocate and DOD after October 2009.) From January

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[5] From January through March 2009, Hawaiian Electric responded to IRs that were submitted by the Consumer Advocate and DOD regarding Hawaiian Electric's updated estimates.

[6] On December 1, 2008, Hawaiian Electric requested, on behalf of the Parties, an extension, until December 23, 2008, to file a stipulated procedural order. The Commission granted the extension to the Parties by letter dated December 18, 2008. On December 23, 2008, the Parties requested additional time to submit a stipulated procedural order, requesting an extension until January 13, 2009. On December 31, 2008, the Commission approved Hawaiian Electric's request, filed on December 23, 2008, for an extension of time for the Parties to file a stipulated procedural order in this docket.

through March 2009, Hawaiian Electric responded to IRs that were submitted by the Consumer Advocate and DOD regarding Hawaiian Electric's updated estimates.

On January 15, 2009, the Parties submitted a Stipulated Procedural Order containing a Schedule of Proceedings, which the Commission approved in its Order Approving, with Modifications, Stipulated Procedural Order Filed on January 15, 2009, issued the same day.

By letter filed January 20, 2009, Hawaiian Electric requested that the Commission amend the Schedule of Proceedings in the Stipulated Procedural Order so as to set the specific date by which an interim decision and order should be rendered in this docket as July 2, 2009. The Consumer Advocate had no objection to the revised Schedule of Proceedings, thereby waiving the five-day period under HAR § 6-61-41(c). By letter filed January 21, 2009, the DOD stated that it did not object to the revised Schedule of Proceedings filed on January 20, 2009. On January 21, 2009, the Commission granted Hawaiian Electric's request with the issuance of its Order Amending Stipulated Procedural Order.

By letter dated April 6, 2009, the Commission advised the Parties that their Statement of Probable Entitlement and Proposed Interim Decision and Order should not include any mechanisms or expenses related to programs or applications that have not been approved by the Commission (e.g., Decoupling, Renewable Energy Infrastructure Program, Solar Saver Pilot Program amendments, Advanced Metering Infrastructure Program).

On April 17, 2009, the Consumer Advocate and DOD filed their Testimonies, Exhibits and Workpapers with respect to revenue requirements. On April 28, 2009, the

Consumer Advocate and DOD filed their Testimonies, Exhibits and Workpapers with respect to cost of service and rate design.

The Consumer Advocate and DOD conducted extensive discovery in this docket, prior to the submission of their testimonies. Hawaiian Electric responded to 504 IRs submitted by the Consumer Advocate and 133 IRs submitted by the DOD, some of which responses were further supplemented during the settlement negotiation process. In addition, Hawaiian Electric's witnesses and supporting staff met with or participated in telephone conferences with the expert consultants retained by the Consumer Advocate and the DOD on numerous occasions to review the exhibits, workpapers and other data supporting the test year revenue requirements.

On April 24 and 27, 2009, Hawaiian Electric submitted IRs relating to the revenue requirements testimonies of the Consumer Advocate and DOD. By letter dated May 14, 2009, Hawaiian Electric withdrew a number of the IRs submitted to the Consumer Advocate. On May 15, 2009, DOD submitted responses to Hawaiian Electric's IRs.

On May 15, 2009, the Parties filed their Settlement Agreement, in which the Parties stated that they reached agreements on all but two issues in this proceeding: (1) what is the appropriate test year expense for informational advertising; and (2) what is the appropriate return on common equity for the test year. The Parties agreed that these two issues should be addressed at the evidentiary hearing.[7] The Parties further agreed that the amount of the interim rate increase to which Hawaiian Electric is probably entitled under HRS § 269-16(d) is $79,820,000 over revenues at current effective rates.

On May 18, 2009, Hawaiian Electric filed its Statement of Probable Entitlement, including a Proposed Interim Decision and Order, in which Hawaiian Electric requested an interim rate increase in the amount of $79,811,000.[8]

On May 22, 2009, Hawaiian Electric filed Rebuttal Testimonies, Exhibits and Workpapers.

On June 3, 2009 and June 9, 2009, the DOD submitted first and second rounds of rebuttal information requests ("RIRs"), respectively. By letter dated June 12, 2009, the Consumer Advocate submitted its first round of RIRs on revenue requirements. By letter dated June 23, 2009, the Commission granted the Consumer Advocate's June 12, 2009 request for an extension of time until July 8, 2009 to submit RIRs to Hawaiian Electric.

On July 2, 2009, the Commission issued its Interim Decision and Order ("Interim Decision and Order"), which approved in part and denied in part Hawaiian Electric's request to increase its rates on an interim basis, as set forth in Hawaiian Electric's Statement of Probable Entitlement. As discussed in the Interim Decision and Order, the Commission determined that Hawaiian Electric had not met its burden of proving that it was probably entitled to recover several cost items, including, certain costs related to the Hawaii Clean Energy Initiative ("HCEI") that were not yet approved by the Commission, but which were included in the Statement of Probable Entitlement. Thus, the Commission instructed Hawaiian Electric to exclude those costs, and file revised schedules with the Commission, together with written explanations as to the amounts

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[7] The Parties further waived their rights to: (a) present further evidence on the settled issues, except as provided in the Settlement Agreement; and (b) conduct cross-examination of the witnesses who are not testifying on the contested issues at the evidentiary hearing. See id. at 2.
[8] Hawaiian Electric explained that the amount of interim increase requested in its Statement of Probable Entitlement is lower by $9,000 than the amount in the Settlement Agreement due to the finalization of the revenue requirement run. See Statement of Probable Entitlement, at 1.

removed, and any other downward adjustments made to the schedules due to the exclusion of the costs for interim relief purposes. The Commission allowed the Consumer Advocate and the DOD to file comments on Hawaiian Electric's revised schedules within five days of the date of filing.[9]

The Interim Decision and Order also identified a number of additional issues (in addition to the two remaining disputed issues identified in the Statement of Probable Entitlement and Stipulated Settlement Letter) that the Commission found to merit further examination such that they may be at issue in the evidentiary hearing.

On July 8, 2009, Hawaiian Electric filed its Revised Schedules and explanations of certain adjustments to Hawaiian Electric's 2009 test year estimates, as required by the Interim Decision and Order.

On July 15, 2009, the Consumer Advocate filed comments on the Revised Schedules.[10] On July 17, 2009, Hawaiian Electric filed a response to the Consumer Advocate's July 15, 2009 letter.

By letter dated July 17, 2009, the Commission rescheduled the hearing in this docket to begin the week of October 26, 2009 and the prehearing conference to the week of October 19, 2009.

On July 20, 2009, Hawaiian Electric submitted its Supplemental Testimonies, Exhibits, and Workpapers to the Commission. On July 21, 2009, Hawaiian Electric received Supplemental Testimonies and Exhibits from the Consumer Advocate and the DOD.

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[9] In addition, the Commission set forth in the Interim Decision and Order, certain issues that the Commission determined were not fully supported in the present record, and for which additional testimony by the Parties is needed. The Commission allowed the Parties to file supplemental testimonies on these issues by July 20, 2009.

On July 28, 2009, Hawaiian Electric completed the filing of responses to RIRs from the Consumer Advocate and the DOD.

By Order Approving Hawaiian Electric's Revised Schedules, issued August 3, 2009, the Commission approved the revised schedules filed by Hawaiian Electric on July 8, 2009 ("Revised Schedules"), as required in Section II of the Commission's Interim Decision and Order, thereby allowing Hawaiian Electric to increase its rates to such levels as would produce, in the aggregate, $61,098,000 in additional revenues, or a 4.71% increase over revenues at current effective rates[11] for a normalized 2009 test year.

In accordance with the Commission's August 3, 2009 Order Approving Hawaiian Electric's Revised Schedules, on August 3, 2009, Hawaiian Electric filed (1) revised index and tariff sheets reflecting Interim Rate Increase surcharges, implementing a revenue increase of $61,043,600, and the removal of Schedule E from Hawaiian Electric's rate schedules; (2) supporting work papers; and (3) an exhibit showing the bill impact of the interim rate increase for a 600 kWh per month residential bill.

During the period from July 27, 2009 through October 28, 2009, the Commission issued and the Parties responded to information requests.

On September 28, 2009, the Commission advised the Parties that the Commission intended to organize the evidentiary hearing in this proceeding by issue panels as the Commission had done in investigative dockets in the past.[12]

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[10] The DOD did not file comments on the Revised Schedules.

[11] Revenues at current effective rates are revenues from base rates, revenues from the energy cost adjustment clause and revenues from the interim rate increase that went into effect on November 1, 2008 in Hawaiian Electric's 2007 test year rate case, Docket No. 2006-0386.

[12] See letter from Commission to Parties dated September 28, 2009 ("September 28th Letter").

On October 7, 2009, the Commission issued a Notice of Panel Hearing and Prehearing Conference, setting a prehearing conference date of October 19, 2009 and a panel hearing to take place from October 26, 2009 through November 6, 2009.

By letter dated October 7, 2009, Hawaiian Electric, on behalf of itself, the Consumer Advocate, and DOD, informed the Commission that the Parties agreed to the panel hearing format described in the September 28th Letter.

On October 12, 2009, the Commission identified the issues that would be covered in the hearing. On October 19, 2009, the Parties provided their respective witness lists and proposed hearing schedule.

On October 19, 2009, the Commission held a prehearing conference pursuant to Hawaii Administrative Rules § 6-61-36, with representatives from Hawaiian Electric, the Consumer Advocate, and the DOD. On October 20, 2009, the Commission issued a Prehearing Conference Order. By letter dated October 21, 2009, the Commission issued a "Brief Outline of Questions for the Panel Evidentiary Hearing" for the Parties' use and information.

The Commission held hearings from October 26 - 30, 2009, and from November 2 - 4, 2009, using a panel hearing format for issues raised by the Commission's review of the record and settlement agreement, and a traditional hearing format for the two contested issues. The Parties presented their closing arguments on November 4, 2009. The official transcript of the hearings was filed on November 23, 2009.

By motion filed November 19, 2009, Hawaiian Electric requested that the Commission issue a second interim decision and order.

On December 1, 2009, the Consumer Advocate filed Comments on HECO's Motion, in which the Consumer Advocate stated that it did not object to Hawaiian Electric's request for an additional interim increase of $12,671,000 representing revenue requirements for the Campbell Industrial Park Combustion Turbine Unit Project pursuant to Hawaiian Electric's proposals offered as Options 1 and 2. The Consumer Advocate objected to Hawaiian Electric's proposed alternative relief in the form of continued AFUDC for the CT-1 investment.

By letter dated December 15, 2009, in conjunction with Hawaiian Electric's November 19, 2009 Motion, Hawaiian Electric submitted a proposed second interim decision and order for the Commission's use.

By letter dated December 15, 2009, the Consumer Advocate requested, on behalf of the Parties, an extension from December 21, 2009 to January 5, 2010 to file opening briefs and from January 11, 2010 to January 26, 2010 to file reply briefs. The Commission granted the extension to the Parties by letter dated December 18, 2009.

EXHIBIT B

CIP CT-1 PROJECT STATUS

The status of the Campbell Industrial Park Generating Station and Transmission Addition Project ("CIP CT-1 Project"), and the test year costs for the CIP CT-1 Project, are covered in the Statement of Facts attached to Hawaiian Electric's motion for a second interim rate increase ("Motion"), filed November 9, 2009, and are summarized below. Since the filing of the motion, developments with respect to CIP CT-1 (which have been reported in other on-going dockets, as summarized below) have included completion of the water treatment system, successful completion of biodiesel testing, and filing of the application for the two-year operational supply of biodisel.

1. CIP CT-1 Project Status and Test Year Cost Estimate

CIP CT-1 Project Status

The Campbell Industrial Park Generating Station and Transmission Addition Project ("CIP CT-1 Project") includes (1) the construction of a new generating facility (including the acquisition of a nominal 100 MW simple-cycle combustion turbine generator and related equipment and auxiliary facilities) (CT-1), (2) an approximately two-mile long 138 kV transmission line ("Transmission Line"), (3) expansion of Hawaiian Electric's existing Barbers Point Tank Farm site , (4) substation upgrades for the AES substation, Campbell Estate Industrial Park ("CEIP") Substation and Kahe Substation ("Substation Upgrades"), and (5) auxiliary equipment and facilities related to the foregoing.

Project components that were already placed in service as of the date of filing Hawaiian Electric's supplemental testimonies (July 20, 2009) included:

- AES Substation (P0001051) – April 9, 2009
- CEIP Substation (P0001052) – April 22, 2009

- CIP Land (P0001084) – November 28, 2008[1]
- Microwave Communications (P0001135) – June 3, 2009
- Kalaeloa Relays (P0001137) – April 1, 2009

The estimated in-service dates for the remaining components were as follows:

- Generating Station (P4900000) – July 31, 2009
- Transmission Line (P0001050) – July 27, 2009
- Fiber Communication (P0001134) – July 27, 2009
- Kahe Breakers (P0001136) – August 31, 2009

The combustion turbine-generator was completed and placed in service (i.e., tied into the electrical grid and producing power) on August 3, 2009. The transmission line and fiber communication components were completed as scheduled on July 27, 2009, and the Kahe breakers work was completed on October 1, 2009.

For the generating station component, two subcomponent systems were not completed as of August 3, 2009, including the two blackstart generators and the water treatment system. The blackstart generators (estimated to cost approximately $3,000,000) were completed and placed in service as of October 15, 2009.[2]

Based on standard accounting practices, Hawaiian Electric discontinued the accrual of AFUDC as of the dates components were placed in service.[3]

By letter dated and filed December 16, 2009, Hawaiian Electric notified the Commission that the water treatment system (estimated to cost approximately $6,500,000) was placed into service on December 15, 2009. The later in-service date for this subcomponent did not affect the operation of the generating unit. Until the water treatment system was in service, demineralized water was provided at the CIP CT-1

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[1] The land and land rights were acquired in 2008, and should be included in rate base from that date, since they do not constitute depreciable property.
[2] Declaration of Robert Isler attached to the Motion at 1.
[3] Declaration of Robert Isler attached to the Motion at 1.

generating station by trucking in water from one of the nearby independent power producers or from other Hawaiian Electric generating stations.

CIP CT-1 Project Cost

The estimated capital costs of the CIP CT-1 Project for purposes of this rate case are $163,279,651, as shown on HECO-S-1701. Of that amount, however, $1,809,875 represents the cost of the parcel between Hanua Street and the AES Substation that is now included in Property Held for Future Use, and no longer included in the cost of any of the project cost components. HECO-S-1701.

Of the remaining $161,469,776, (1) $6,119,685 represents the cost of land and easements acquired for the project in 2008, which is included in Property Held for Future Use in the beginning of the test year rate base balance amount, and in plant-in-service in the end of test year rate base balance amount, and (2) $155,350,091 represents the costs of the other components.

It should be noted that the total project cost estimate includes $50,000 that was estimated to be expended in 2010, and was not included in the test year rate base estimate. As a result, the test year cost estimate for the project is $161,419,776 (i.e., $163,279,651, less $1,809,875 included in Property Held for Future Use, and less $50,000 estimated to be incurred in 2010).

The total cost estimate for the project has been updated to approximately $193.1 million, as shown in HECO-S-17A01, and as supported in HECO ST-17A.[4] Nonetheless, given the settlement with the other Parties, and the timing of the availability of the

[4] Hawaiian Electric submitted a detailed explanation of the updated costs in testimonies submitted in this proceeding and in the cost report submitted in Docket No. 05-0145. The record (including the testimony provided during the Panel 5 hearing), supports Hawaiian Electric's position that, although the costs for the CIP CT-1 project were substantially underestimated, the actual costs incurred were prudent.

updated cost estimate, Hawaiian Electric has not proposed that the cost estimate included in the stipulated settlement be adjusted to reflect the updated current cost estimate supported in its supplemental testimonies.

As of October 31, 2009, the total costs recorded for the components and subcomponents that are included in plant in service include (1) $6,119,685 for the cost of land and easements acquired for the project in 2008, and (2) $164,735,637 for the other components (excluding the water treatment system, for which $4,674,765 had been recorded to CWIP). The amount recorded as of October 31, 2009 of $177,339,962 is over $14,000,000 in excess of the test year estimate of $163,279,651. The estimated costs to be incurred in the last two months of 2009, and in 2010 for the components that have been closed to plant in service include costs for work related to the plant site (including road paving, lighting, cameras, security and other miscellaneous work), and remaining construction management services. In addition, the costs related to certain of the change orders in the construction contracts are being negotiated. The estimated costs for 2010 reflect costs related to spare parts specific to the project that are not expected to be received until 2010.[5]

Operation and Maintenance Costs for CIP CT-1

Prior to settlement discussions and the ensuing adjustments, $1,474,000 of costs were identified with the Production O&M expenses of CIP CT-1.[6] As part of settlement negotiations and IR response commitments, Hawaiian Electric agreed to reduce its Production O&M expenses by $105,000 related to the removal of waste water treatment

[5] Declaration of Robert Isler attached to the Motion at 1-2.

[6] The components of the $1,474,000 CIP CT-1 Production O&M expenses are set forth in HECO T-7 Rate Case Update, Attachment 14, at 4, column F. See also HECO T-7 Rate Case Update, Attachment 14, at 3, columns D, E and F; HECO T-7 Rate Case Update, Attachment 14, at 1; and HECO T-7 Rate Case Update, Attachment 14, at 5.

chemicals ($49,000), boiler water treatment ($42,000), and demin/evap chemicals ($14,000).[7] Thus, the resulting production O&M costs associated with CT-1 is $1,369,000 as reflected in the Statement of Probable Entitlement ($1,474,000 - $105,000).

Fuel Inventory

As explained on page 70 of Exhibit 1 of the Stipulated Settlement Letter, for purposes of settlement the Parties agreed to accept Hawaiian Electric's April 2009 Update production simulation results, including Hawaiian Electric's December 2008 fuel prices, and the Company's updated average fuel inventory balance of $45,005,000 for the 2009 test year. As shown on page 8 of HECO T-5 Attachment 1 to the Stipulated Settlement Letter, the Company derived this amount by computing the average of the beginning of 2009 test year fuel inventory (without CIP CT-1) of $43,274,000 and the end of 2009 test year fuel inventory (with CIP CT-1) of $46,737,000. Because CIP CT-1 will use biodiesel for fuel and was scheduled to go into service on July 31, 2009, the beginning of test year fuel inventory does not include any biodiesel but the end of test year fuel inventory does. Removal of CIP CT-1 from the test year required the removal of biodiesel from the end of test year fuel inventory. To be conservative, the Company used the beginning of test year balance of $43,274,000 (which does not include biodiesel) for the end of test year fuel inventory, resulting in an average annual total inventory of the same amount ($43,274,000) for the 2009 test year. As shown in Hawaiian Electric's Revised Schedules Resulting from Interim Decision and Order, Exhibit 3, HECO T-5 Attachment 1, the adjustment resulting from the ID&O was a reduction of $3,463,000 to the end of year total inventory. The adjusted average annual total inventory amount of

[7] Stipulated Settlement Letter, Exhibit 1, at 29 summarizes the three adjustments agreed to in responses to CA-IR-297 and CA-IR-468.

$43,274,000 was conservative since the end of test year fuel inventory reflected in the Stipulated Settlement Letter included 780,727 barrels of fuel, or 16,785 more than the beginning of test year balance of 763,942 barrels. HECO T-5 Attachment 1 of the Stipulated Settlement Letter, at 8. By using the inventory value of $43,274,000 for the end of test year balance for the purposes of this adjustment, the Company effectively used the lower amount of 763,942 barrels for both the beginning and end of test year balances.

Hawaiian Electric is no longer requesting that any biofuel inventory for CIP CT-1 be included in the 2009 test year fuel inventory.

Accumulated Deferred Income Taxes

The Parties agreed to the test year estimate of the accumulated deferred income taxes ("ADIT") associated with CIP CT-1. See Stipulated Settlement Letter Exhibit 1 at 73. The total ADIT associated with CIP CT-1 was calculated to be $4,518,000 and the impact on average rate base was $2,259,000 in the 2009 test year. In accordance with the Interim Decision and Order, Hawaiian Electric excluded this ADIT from rate base in calculating the revenue requirements for purposes of the 2009 initial test year interim rate relief. The exclusion of the ADIT associated with CIP CT-1 had the effect of decreasing ADIT (increasing rate base). See Hawaiian Electric's July 9, 2009 Additional Schedule Resulting from Interim Decision and Order, Exhibit 3, at 9.1. In calculating the amount of the requested second interim increase, Hawaiian Electric has added back the $2,259,000 of ADIT associated with CIP CT-1 that was excluded in accordance with the Interim Decision and Order (which reduces rate base).

2. CIP CT-1 Biofuel Status

Although the CIP CT-1 has been placed in service and is fully capable of serving customer load, Hawaiian Electric is still in the process of obtaining biodiesel supplies for the unit.[8]

Until proper approvals and permits are received to operate CIP CT-1 on biofuels and biofuels are available, the unit will not be operated to serve customer load except pursuant to the Commission's orders or instructions.[9] Once biofuel test burn data is available, Hawaiian Electric will submit a permit modification application to the State of Hawaii, Department of Health ("DOH") using the data to authorize using biodiesel as a fuel, *in conformance with the joint stipulation ("Joint Stipulation") submitted as Exhibit* A to the Joint Motion For Approval of Stipulation filed by Hawaiian Electric and the Consumer Advocate on December 4, 2006 in Docket No. 05-0145, and accepted by the Commission in its final order. (In parallel, Hawaiian Electric has submitted a permit modification application to the DOH, which among other things, establishes a mechanism allowing more operational flexibility, including addressing scenarios with different biofuel feedstocks, e.g., if market availability or cost considerations were to require switching from one type of biofuel to another on relatively short notice.[10]) Once the amended air permit is received, the unit will be running on biodiesel, except under

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[8] Declaration of Cecily A. Barnes attached to the Motion at 1.

[9] In its Decision and Order filed August 5, 2009 ("August 5, 2009 D&O") in Docket No. 2007-0346, the Commission notes that its order approving the stipulation requires Hawaiian Electric to operate CT-1 using only 100% biofuel, and "reminds HECO that it cannot operate CT-1 using a fuel other than 100% biofuels, absent prior approval of the commission." Id. at 5 n.9, citing Decision and Order No. 23457 at 2.

[10] The proposal is expected to provide a long-term support for biofueling, in that it would allow for a more streamlined method to obtain DOH authorization for use of alternative biofuels in the future. Specifically, under the recently submitted permit modification application, a significant modification would not be necessary each time a different biofuel is used so long as the DOH determines that the biofuel meets requirements that will be established in advance through this modification.

limited emergency circumstances in which biodiesel is unavailable. See response to PUC-IR-117 at 4-5.

Use of Biofuel in CIP CT-1

In the CIP CT-1 docket, Docket No. 05-0145, the Consumer Advocate recommended,[11] and Hawaiian Electric agreed, to fuel the new generating unit using 100% biofuel. The Commission agreed that burning biofuel is preferable to fossil fuels and approved its use according to the Joint Stipulation, subject to the Commission's approval of the specific fuel purchase contract for the biofuel.

By Decision and Order No. 23457, filed on May 23, 2007 in Docket No. 05-0145 ("D&O 23457"), the Commission approved Hawaiian Electric and the Consumer Advocate's Joint Motion for Approval of Stipulation, thereby approving Hawaiian Electric's request to commit funds for the purchase and installation of CT-1 and a new 138 kilovolt transmission line. The Commission noted that its "decision [was] based on the undisputed urgent need for new generation by HECO, and the fact that State policy and law support HECO's commitment to use 100% biofuels in the new generating unit." D&O 23457 at 2.

In approving the Joint Stipulation, the Commission stated, "[a]s to HECO's commitment to use 100% biofuels, the commission finds that commitment to be reasonable and consistent with State policy to reduce Hawaii's dependence on imported fossil fuels and encourage sustainability through economic diversification, export

[11] The Consumer Advocate did not object to the commitment of funds for the project, provided the combustion turbine used 100% biofuels. The Consumer Advocate recommended that Hawaiian Electric be required to use ethanol or some other biodiesel fuel, as opposed to naphtha, for the generating unit, and that Hawaiian Electric be required to work with the Department of Business, Economic Development & Tourism to develop a local resource for biofuels. CA-T-1, filed August 17, 2006 in Docket No. 05-0145.

expansion, and import substitution." D&O 23457 at 45. The Commission further found that "using biofuels, which may eventually be locally grown and produced, is preferable to burning fossil fuel for the [CT-1] Project, and will advance the State's policies of reducing the State's dependence on fossil fuels and diversifying the State's economy." D&O 23457 at47-48.

As discussed in Docket No. 05-0145, because biodiesel is a new fuel to be used in CIP CT-1, Hawaiian Electric must obtain a modification of its air permit from the Hawaii Department of Health ("DOH") to operate CIP CT-1 on biodiesel. See Exhibit A to Biofuels Stipulation; see also response to PUC-IR-117 at 6-7; HECO ST-17E at 9; HECO ST-17A at 41.

Hawaiian Electric presented its plan for obtaining the requisite air permit modification from the DOH in Docket No. 05-0145, as described in Exhibit A to the Joint Stipulation):[12]

> Modify the Air Permit to Allow Use of the Chosen Biofuel
>
> 5. Hawaiian Electric will work with the Department of Health ("DoH") to provide a permitting process that will lead to permits to bum biofuels in the CT Unit.
>
> 6. Because the emissions data does not currently exist for biofuels and in order to ensure that ratepayer funds are spent effectively and wisely, Hawaiian Electric will implement the following process:
>
> a. In general, the CT unit will go through acceptance testing using naphtha or low sulfur diesel in order to ensure that the CT Unit meets contract specifications and air permit requirements.
>
> b. Following acceptance of the CT Unit, Hawaiian Electric will request DoH's approval to conduct testing at different loads using the chosen biofuel for which a supply contract has been executed, and to gather the

[12] Exhibit A (Position on Biofuels for the New Combustion Turbine Unit) to Stipulation between Hawaiian Electric and Consumer Advocate, dated December 4, 2006, submitted with Joint Motion for Approval of Stipulation, filed December 4, 2006 in Docket No. 05-0145.

emissions data needed to modify the air permit. After emissions data is collected using samples of the selected biofuel (i.e., biodiesel or ethanol), HECO will seek to modify the air permit to also allow 100% use of that biofuel. This entire process of collecting emissions data and modifying the permit could take up to 6 months depending on DoH requirements.

c. Following the air permit modification, the unit will then be run by burning biofuel (100%).

Aggressive Implementation of the Process

7. Hawaiian Electric commits to an aggressive implementation of this process to run the CT Unit on one hundred percent (100%) biofuel, subject to the requirements of the Commission and DoH.

8. If there is an interruption of the biofuel supply or an emergency or operational problem that would affect the use of the CT Unit, Hawaiian Electric will work with the Consumer Advocate and the Commission to attempt to address such contingencies.

Once CIP CT-1 was placed in-service, Hawaiian Electric conducted performance guarantee testing using low sulfur diesel to determine if CIP CT-1 met Siemens' performance guarantees.[13]

There has been a gap between the time that (1) the CIP CT-1 generating unit was placed in service, and the performance guarantee testing under the Siemens contract was subsequently completed, and (2) biodiesel will be available for the conduct of the emissions testing.

[13] If CIP CT-1 did not meet those guarantees, then Siemens had up to nine months to address those performance issues. If Hawaiian Electric used biodiesel to operate CIP CT-1 prior to Siemens demonstrating achievement of the performance guarantees, then the performance guarantees would have been automatically deemed successfully achieved, regardless of actual performance. Thus, Hawaiian Electric always intended to use biodiesel for emissions testing after the performance guarantees were achieved or remedied under the Siemens contract. See Exhibit A to Biofuels Stipulation; see also testimony and cross-examination of Robert Isler during the supplemental Imperium Contract hearing in Docket No. 2007-0346 on March 10, 2009, Vol. II at 445-460; HECO ST-17A at 39-41; testimony of Joseph Herz during the hearings in this proceeding.

There will be another gap in time, which has always been anticipated, between the completion of the biodiesel emissions tests[14] and the modification of the air permit for CIP CT-1 to permit the burning of biodiesel on an on-going basis.[15] See Exhibit A to Joint Stipulation, which states that the process of collecting emissions data and modifying the air permit could take up to 6 months. See also Response to PUC-IR-117 at 5-7, 11-12; and HECO ST-17E at 9-11.

Depending on the time required for approval of a new contract for the operational supply of biodiesel, and initial deliveries of biodiesel under the new contract, there could be a further gap in time between the modification of the air permit and the availability of biodiesel for full time operation of the unit.

Hawaiian Electric's initial efforts to secure an operational supply of biofuel were unsatisfactory to the Commission, as it clearly indicated in rejecting the amended Imperium Contract.

Hawaiian Electric cannot redo the Imperium contract or amendment now. But it has endeavored to address the need for a new RFP process and to acquire the emissions test fuel as rapidly as possible. See response to PUC-IR-117 at 8-11, 12-13, and Declaration of Cecily Barnes dated November 19, 2009 attached to the Motion.

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[14] The purpose of the biodiesel testing is to gather emissions data that will be provided to DOH. DOH will review that information and Hawaiian Electric has testified that it anticipates that it will take DOH anywhere from 2 to 6 months to review the request for permit modification. See Exhibit A to Biofuels Stipulation; see also testimony and cross-examination of Robert Isler during the supplemental Imperium Contract hearing in Docket No. 2007-0346 on March 10, 2009, Vol. II at 445-460; HECO ST-17A at 39-41.

[15] It was the understanding of Hawaiian Electric, and appears to have been the understanding of the Consumer Advocate, that CIP CT-1 would be operated on diesel fuel during the gap period after emissions testing was completed, and the air permit was modified. See testimony and cross-examination of Robert Isler during the supplemental Imperium Contract hearing in Docket No. 2007-0346 on March 10, 2009, Vol. II at 445-460; HECO ST-17A at 41 (R. Isler).

Given the Commission's understanding, as expressed in the Imperium D&O, that the unit will be operated only on biodiesel, except for testing and emergency use, the use of CIP CT-1 will be limited to those purposes pending the availability of an operational supply of biodiesel.

Acquisition of Biofuel for CIP CT-1

On December 27, 2006, Hawaiian Electric issued a New Capacity Biofuel Supply Request for Proposals ("Original RFP"). Hawaiian Electric received seven proposals in response to its RFP. Hawaiian Electric hired Black and Veatch Corporation ("Black and Veatch") to evaluate and provide guidance on the proposals. Based on Black and Veatch's recommendations, Hawaiian Electric entered into negotiations with Imperium Services, LLC ("Imperium"), which resulted in a contract between Hawaiian Electric and Imperium for a biodiesel fuel supply for CT-1 ("Original Contract").

On October 18, 2007, Hawaiian Electric filed its Application in Docket No. 2007-0346 seeking Commission approval of the Original Contract.

On January 30, 2009, Hawaiian Electric filed Amendment No. 1 to Biodiesel Supply Contract Between Hawaiian Electric Company, Inc. and Imperium Services, LLC and Assignment to Imperium Grays Harbor, LLC. ("Amendment"). On February 6, 2009, Hawaiian Electric filed the Biodiesel Terminalling and Trucking Agreement ("TTA") with Aloha Petroleum, Ltd. (the Amendment and the TTA collectively referred to as "Amended Contract").

By Decision and Order issued August 5, 2009 ("Imperium D&O"), in Docket No. 2007-0346, the Commission rejected the Imperium biofuels contract, as amended. The Commission noted, "in general, that the terms of the Amended Contract are substantially less favorable to HECO (and therefore its ratepayers) in price, risk, scope, and additional costs than the Original Contract due to the new point of delivery of fuel." Id. at 16.

In response to the Commission's decision, Hawaiian Electric has expeditiously reissued requests for proposals for biodiesel.

Test Supply of Biodiesel

To acquire the biodiesel for the biodiesel emissions data project, Hawaiian Electric issued a Request for Proposal Biodiesel Supply Contract ("RFP") on August 14, 2009. Eight proposals were received by Hawaiian Electric in response to the RFP.

After its evaluation of the proposals, Hawaiian Electric entered into comprehensive negotiations with the successful bidder, REG Marketing and Logistics, LLC ("REG"). On October 1, 2009, Hawaiian Electric executed a contract with REG ("Biodiesel Supply Contract"). The Biodiesel Supply Contract is for approximately 400,000 gallons, the amount of biodiesel estimated by Hawaiian Electric required to conduct testing for the biodiesel emissions data project.

On October 2, 2009, Hawaiian Electric filed an application in Docket No. 2009-0296 requesting Commission approval of a one-time purchase of a supply of approximately 400,000 net U.S. gallons of biodiesel through the Biodiesel Supply Contract, and approval for the inclusion of the costs of the Biodiesel Supply Contract, including without limitation, the costs associated with the biodiesel, transportation, and related taxes, in Hawaiian Electric's Energy Cost Adjustment Clause ("ECAC") to the extent that the costs are not recovered in Applicant's base rates.[16]

On October 6, 2009, Hawaiian Electric placed the order with REG for the biodiesel under the Biodiesel Supply Contract. On October 22, 2009, Hawaiian Electric filed a letter informing the Commission of the October 6, 2009 order placed with REG

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[16] In addition, while Hawaiian Electric is willing to use 100% biodiesel in CIP CT-1, Hawaiian Electric also requested that the Commission allow Hawaiian Electric to use B99 biodiesel blended with no more than 1% petroleum diesel (in addition to 100% biodiesel) in order to benefit from the Federal biofuel blenders' tax credit, currently $1.00 for each gallon of biodiesel mixture. The Biodiesel Supply Contract factors in the Federal biofuel blenders' tax credit in a manner that, in effect, will pass the credit on to Hawaiian Electric's customers.

for 400,000 gallons of biodiesel under the terms of the biodiesel supply contract, and provided a copy of the letter of agreement signed by Hawaiian Electric and REG to effect the order date of October 6, 2009. Hawaiian Electric acknowledges that incurring the costs prior to Commission approval has some risks but given the need to facilitate biodiesel testing of CIP CT-1, Hawaiian Electric has respectfully requested that, if the Commission approves the Biodiesel Supply Contract, the Commission allow all costs incurred to date for the biodiesel contract, to the extent that such costs are not recovered in Hawaiian Electric's base rates, to be deferred and allow such costs to be recovered through the ECAC, pursuant to Section 6-60-6 of the Hawaii Administrative Rules.

By Letter dated and filed January 5, 2010, Hawaiian Electric provided the Commission with an update on the status of its biodiesel tuning and emissions testing of CIP CT-1. The tuning involved systematic burning of biodiesel in the CIP CT-1 at various loads to determine the appropriate operational control settings using biodiesel. The purpose of the emissions testing was to gather data (using the settings determined during tuning) needed for submittal to the Department of Health for a modification to the unit's air permit.

The delivery of biodiesel commenced on November 6, 2009, and was concluded on November 20, 2009. In total, REG delivered approximately 396,000 gallons of biodiesel via 70 5,800 gallon capacity International Organization for Standardization tank containers ("iso tank containers"). The biodiesel was transferred from each iso tank container into a storage tank at the CIP CT-1 facility upon arrival.

The biodiesel tuning and testing commenced on December 3, 2009, and concluded on December 15, 2009. The results of the tuning and testing confirm that biodiesel is a viable fuel for use in CIP CT-1. The minimum load using biodiesel is 40MW since this is the lowest load that both NOx and CO emissions can be maintained within the air permit limits. The emissions data gathered during the testing of CIP CT-1 show that all monitored emissions parameters can be maintained within permit limits while operating between minimum load and baseload. Hawaiian Electric compiled the emissions data and submitted it to the Department of Health on December 31, 2009.

Operational Supply of Biodiesel

In anticipation of the need for biodiesel to operate CIP CT-1 on an on-going basis, Hawaiian Electric also issued its RFP for a two-year supply on August 14, 2009. The RFP requests proposals for the supply and delivery of three million to seven million gallons of biodiesel per year for a term of two years from the contract effective date as subject to Commission approval. Eight proposals were received by Hawaiian Electric in response to the RFP for a two year supply of biodiesel.

On December 22, 2009, Hawaiian Electric filed an application in Docket No. 2009-0353[17] requesting approval of (1) the two-year Biodiesel Supply Contract (CIP CT-1 Operational Volume) Contract Number PIF-09-006 ("Biodiesel Supply Contract") between Hawaiian Electric and Renewable Energy Group Marketing and Logistics, LLC ("REG"), to supply biodiesel for use primarily in CIP CT-1, as well as other Hawaiian Electric generating units, (2) the inclusion of the costs of the Biodiesel Supply Contract, including without limitation, the costs associated with the biodiesel, transportation,

[17] "Biodiesel Supply Contract Application".

storage and related taxes, in Hawaiian Electric's ECAC to the extent that the costs are not recovered in Applicant's base rates, and (3) the use of biodiesel blended with no more than 1% petroleum diesel (in addition to using 100% biodiesel) in order to benefit from the Federal alternative fuel blender's tax credit.[18]

The Biodiesel Supply Contract will become effective upon Hawaiian Electric providing REG written notice of the Commission's approval of the Biodiesel Supply Contract. The Biodiesel Supply Contract also contains a provision to enable Hawaiian Electric and REG to mutually agree to an alternate effective date. The Biodiesel Supply Contract expires two years from the date of the first delivery of biodiesel to the CIP CT-1 facility.[19]

Per the Biodiesel Supply Contract stated lead time, Hawaiian Electric anticipates that approximately 16 weeks are needed to receive the biodiesel from the date the first quantity of biodiesel is ordered under the Biodiesel Supply Contract. This 16 week period provides adequate lead time for REG to manufacture the biodiesel and for transportation of the biodiesel to Hawaiian Electric's CIP Facility.[20]

Biodiesel Summary

Hawaiian Electric understands the Commission's concern, in the wake of the rejection of the Imperium contract, that the Company was not in a position to comply with a key element of the approval of CT-1 – a viable supply of biofuels.

Hawaiian Electric believes that the foregoing demonstrates that supplies of biofuels are available and that the appropriate commitments to obtain them have been met. The Company took to heart the lessons learned in the Imperium case and the current

[18] Biodiesel Supply Contract Application at 1-2.
[19] Biodiesel Supply Contract Application at 7.
[20] Biodiesel Supply Contract Application at 10.

biofuels arrangements can be regarded as real and as viable. Furthermore, by taking the risk of purchasing the initial supply without Commission approval, the Company is fully demonstrating its commitment to meeting the conditions of the order authorizing CT-1. Stated otherwise, to the extent that the Commission was saying that a "used and useful CT-1" needed to be a "used and useful biofueled CT-1," the Company is making clear its compliance with the full condition that went with the approval of CT-1.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing HAWAIIAN ELECTRIC COMPANY, INC.'S OPENING BRIEF, EXHIBITS A and B, together with this CERTIFICATE OF SERVICE, as indicated below by hand delivery and/or by mailing a copy by United States mail, postage prepaid, to the following:

Hand Delivery	U.S. Mail	
X		Dean Nishina, Executive Director Department of Commerce and Consumer Affairs Division of Consumer Advocacy 335 Merchant Street, Room 326 Honolulu, Hawaii 96813
	X	James N. McCormick Theodore E. Vestal Associate Counsels (Code 09C) Naval Facilities Engineering Command, Pacific 258 Makalapa Drive, Suite 100 Pearl Harbor, HI 96860-3134
	X	Dr. Kay Davoodi NAVFAC HQ ACQ-URASO 1322 Patterson Ave., SE Ste. 1000 Washington Navy Yard Washington, DC 20374

DATED: Honolulu, Hawaii, January 5, 2010.

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.